Part 2

Generation Re-dispatch Costs

Re-dispatch generation costs are defined as additional costs that are incurred due to the unpredictability of events that occur during a typical power system operational day. Historically, these types of events were driven by load variations due to actual weather that differs from what was forecasted for the period in question. Most power system operators assess the generation needs for a future period, typically the next day, based on load forecasts and commit a series of generators to be available for operation in that period. These committed generators are expected to operate in an hour-to-hour sequence that minimizes total cost. Once within that period, however, actual load may vary from what was planned and the committed generators may operate in a less than optimal hour-to-hour sequence. The resulting additional costs due to real time variability are known as re-dispatch costs.

As more intermittent generation — like solar or wind — is added to the grid, additional uncertainty about re-dispatch costs is added due to factors such as unpredictable cloud cover or changes in wind speed. In order to assess the resulting re-dispatch costs, the Company performed a simulation analysis to determine the cost impact on generation operations at varying levels of solar, onshore wind and offshore wind penetration. To study the effects of these intermittent resources, the Company studied historic wind speed and solar irradiance data from the NREL.

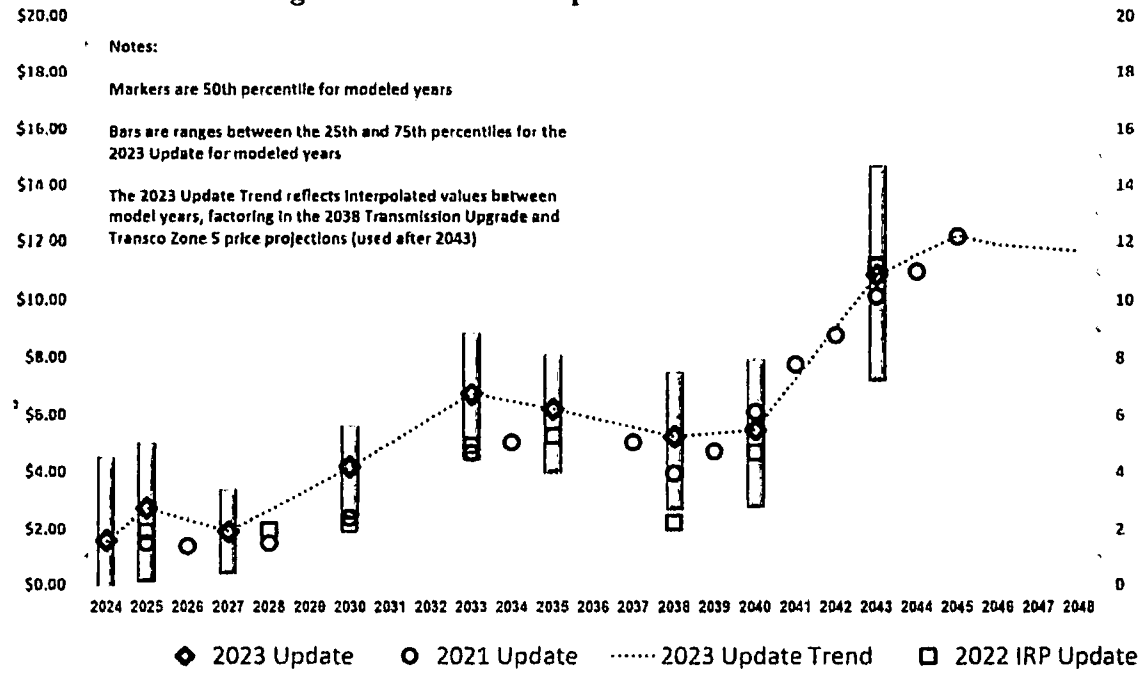
To perform its generation re-dispatch costs analysis, the Company utilized the Aurora planning model with a regional simulation topology consisting of PJM Interconnection, VACAR South, Southern Company, Tennessee Valley Authority, and large sections of Midwest ISO (see map below). The results from the Aurora model captured not only the DOM Zone hourly prices interactively, but also the potential system cost impacts from intermittent resources outside the Company's service territory.

Figure 4.6.3.2– Aurora Model Topology

For each simulation year, the Company performed a base case Aurora simulation by using the base hourly renewable generation profiles to establish the base case commitment decisions. Using these commitment decisions, the Company performed an additional 200 simulations but applying different hourly renewable profiles from the NREL historical weather patterns studies to re-optimize the system cost.

The total system cost for each simulation was compared to the base case system cost of the same year. This delta of the system cost is composed of the respective differences in fuel cost, variable operations and maintenance ("O&M") cost, emission cost, and purchase and sale costs. The re-dispatch cost is the delta of the system cost divided by the Company's expected total renewable generation.

Figure 4.6.3.3 – Re-Dispatch Cost Results



Regulating Reserve Costs

Regulating reserves are defined as additional reserves needed to balance the uncertainty of forecast errors in net load that occur during a typical power system operational day. These reserves exclude contingency reserves, which are defined as the loss of a major power system generation or transmission system asset. Within the PJM market, these regulating reserves are an ancillary service, the cost of which is charged to customers. Revenues collected for this ancillary service are paid to resources available to supply or reduce energy to correct forecast errors. Unlike contingency reserves, regulating reserves are needed to either increase or decrease generation in any given operational hour. These reserves also differ from re-dispatch costs; they are paid to the resource whether they are used or not during the operating hour. The regulating reserve costs ensure that the transmission system has adequate resources available to handle forecast uncertainty. The system pays for regulating reserves so that it has the capability to quickly re-dispatch. In contrast, the operating costs to dispatch these regulating resources (to mitigate forecast errors and stabilize the transmission system) are part of re-dispatch costs.

Historically, the level of regulating reserves was primarily driven by the uncertainty associated with load during any given operating day. The intermittent nature of solar and wind generation adds to this uncertainty. Accordingly, the levels of regulating reserves will need to increase to compensate for this added uncertainty.

A variety of resources can be used to address system uncertainty: energy storage, unscheduled CT capacity, unscheduled duct burner capacity (on scheduled combined-cycle units), intraday purchases and sales, and interruptible load.

In order to assess the increase of regulating reserves that will result from increasing volumes of solar generation, the Company utilized the Electric Power Research Institute Dynamic Assessment and Determination of Operating Reserves tool. This tool calculates operating reserves based on correlations to other variables (*e.g.*, forecasted generation, time of day) and can be used to evaluate solar, wind, and load variations separately and in combination. The reserves volume required is then reduced by the expected geographic diversity of the resources and technological diversity of these resources (wind vs. solar).

Once the MW volume of solar and wind was determined as described above, the next phase of the analysis was to determine a market price for these reserves. This was based on a historical analysis of PJM day-ahead secondary reserves and is capped by the cost of new entry of a new combustion turbine resource. The results of this analysis reflect the hourly cost of regulating reserves gradually increases from $0.67/MWh in 2024 to $14.29/MWh in 2048. This occurs because the rate that PJM is forecasted to increase the need for regulating reserves (driven by the level of renewables build) grows more quickly within PJM than the projected addition of resources that provide regulation reserves in PJM. The forecasts of resource additions are based on ICF projections in states other than Virginia. Virginia resource additions are based on the projections in this 2023 Plan for the Company; for Appalachian Power Company and other sellers of electric power in Virginia, the projections assume solar and wind resource additions according to the RPS requirements for Appalachian Power Company.

From the Company's perspective, regulating reserve costs will be incurred when the regulating costs to serve the Company's load exceed the revenue received from PJM for the Company units that supply this ancillary service.

Figure 4.6.3.4 – Net Regulating Reserves Cost of Market Purchases ($M)

Year	Plan A	Plan B	Plan C	Plan D	Plan E
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0
2028	$4	$0	$0	$0	$0
2029	$24	$0	$13	$0	$0
2030	$51	$0	$39	$0	$0
2031	$78	$0	$0	$0	$0
2032	$97	$0	$0	$0	$0
2033	$103	$110	$125	$110	$122
2034	$266	$126	$156	$126	$133
2035	$278	$101	$185	$138	$140
2036	$292	$72	$215	$149	$150
2037	$192	$46	$213	$163	$182
2038	$164	$15	$208	$174	$194
2039	$133	$22	$242	$161	$167
2040	$105	$33	$282	$137	$143
2041	$70	$39	$316	$196	$201
2042	$33	$44	$351	$168	$170
2043	$0	$54	$392	$210	$212
2044	$0	$60	$431	$178	$180
2045	$0	$65	$469	$230	$202
2046	$0	$76	$514	$251	$220
2047	$0	$82	$556	$265	$233
2048	$0	$90	$598	$269	$245

4.8 Storage-Related Assumptions

All storage developed in this 2023 Plan is assumed to be four-hour, lithium-ion batteries, though the Company is pursuing a long duration storage pilot as well. For the planning period, all plans were limited to 300 MW per year. In order to reach net zero, Alternative Plans D and E allowed 900 MW per year after 2038. In Alternative Plans B and D, the Company set constraints requiring the PLEXOS model to select 2,700 MW of energy storage by 2035, consistent with the VCEA. Third-party owned energy storage will make up 35% of the 2,700 MW. The Company plans to meet interim VCEA targets, but storage development will be more heavily weighted to the later part of the planning period, when more renewable penetration increases the value of battery storage and additional technology options are commercially available.

4.9 Gas Transportation Cost Assumptions

Natural gas is largely delivered on a just-in-time basis. Vulnerabilities in natural gas supply and transportation must be sufficiently evaluated from a planning and reliability perspective.

Mitigating strategies such as storage, peaking services, on-site fuel capability, firm natural gas supply purchases, firm pipeline transportation capacity, alternate pipelines, dual-fuel capability, access to multiple natural gas supply basins, and overall fuel diversity all help to alleviate this risk.

There are two main types of pipeline transportation service contracts: firm and interruptible. Natural gas delivered using a firm pipeline transportation service contract is available to the customer during the contract term and is not subject to a prior transportation service claim from another customer. The Company regularly uses both primary and secondary receipt and delivery flexibility inherent in its pipeline firm transportation contracts to reliably deliver fuel to its gas-fired generation fleet. While a pipeline force majeure event can interrupt primary, firm transportation service, pipeline constraints, and restrictions can limit some or all secondary receipt / delivery flexibility, beyond primary firm contractual rights. Additionally, for firm natural gas supply to be delivered reliably, sufficient supply must be scheduled in accordance with FERC-approved pipeline nomination cycles, flow rules, and then- effective pipeline constraints and restrictions.

For a firm pipeline transportation and/or storage service contract, the customer pays a monthly capacity reservation charge that recovers its share of FERC-approved pipeline fixed costs supporting the firm service. Interruptible pipeline transportation service contracts provide transportation subject to the contractual rights of firm customers and other pipeline constraints and restrictions. The Company predominantly uses firm pipeline transportation and firm storage services to fuel its natural gas-fired generation fleet but can also use interruptible pipeline transportation service depending on availability and PJM-directed need for gas-fired generation.

The Company included natural gas pipeline transportation and storage costs in its modeling. The Company predominantly uses firm pipeline transportation and storage to fuel its combined-cycle facilities. Additionally, the Company can utilize a firm pipeline transportation service not otherwise needed for its combined-cycle facilities, to fuel its CTs. When available, the Company can utilize interruptible pipeline transportation service for CTs because these peaking resources typically operate with less than 20% capacity factors and are typically equipped with on-site backup fuel. When setting capacity factor limits for new incremental CT units, the Company assumed gas availability in the spring, summer, and fall, with oil only operations in the winter when gas is most constrained.

The Company continually evaluates its generation fueling portfolio (including firm and interruptible natural gas pipeline transportation services) with fuel deliverability, flexibility, and affordability in mind. Specifically for natural gas, given the physical location of the Company's gas-fired generation fleet is in a fully subscribed pipeline corridor, pipeline constraints and associated restrictions to secondary flexibility rights are commonplace. Therefore, in the interest of generation fuel reliability, the Company requests and reviews proposals (covering various terms) for incremental firm transportation, pipeline storage, peaking services, and onsite fueling (oil or LNG). For example, given the current construction and regulatory uncertainties associated with new natural gas pipeline builds, natural gas peaking services or on-site LNG can be effective options to place specified amounts of natural gas fuel at specified locations for peak periods.

4.10 Social Cost of Carbon

The social cost of carbon is an estimate in dollars of the economic damages that result from emitting one ton of carbon into the air. For the past two years, the Company has incorporated a social cost of carbon dispatch adder in its modeling assumptions; however, given the higher federal carbon forecast assumptions received in the ICF forecast this year, the carbon adder seemed duplicative. The Company continues to believe that some federal economic incentive will be required for the country to reduce emissions and will revisit this assumption in future modeling. The Company will also continue to consider the social cost or benefit of carbon in future CPCNs as required.

4.11 Least-Cost Plan Assumptions

Alternative Plan A presents a least-cost plan using assumptions required by the SCC. Specifically, Plan A uses the 2023 PJM Load Forecast adjusted for only existing and proposed energy efficiency, consistent with prior SCC orders. It meets only applicable carbon regulations and the mandatory RPS Program requirements of the VCEA; see Section 4.4, ***Commodity Price Assumptions*** and Section 5.2.3, ***Environmental Regulations***, for the Company's assumptions regarding "applicable carbon regulations." For Plan A, the Company did not force the model to select any specific resources and did not exclude any reasonable resource options. Consistent with this directive from prior orders, the Company did not exclude carbon-emitting resources as an option to reliably meet customers' energy and capacity needs. The Company also included reasonable build constraints in Plan A, including the 900 MW annual solar limit. The potential unit retirements shown in Plan A are those selected by PLEXOS without regard for other factors that the Company considers when evaluating unit retirements, as discussed further in Section 5.2.1, ***Retirements***.

4.12 PLEXOS Modeling Refinements

The Company has included several refinements to PLEXOS since the 2020 Plan to incorporate the many requirements of the VCEA, including:

- A dynamic RPS Program requirement based on forecasted customer sales;
- The ability to purchase RECs from eligible market sources to satisfy a portion of the Company's RPS Program requirements;
- An adjustment to the REC requirement to account for ARB customers, maintaining 2022 ARB certification percentages;
- Deficiency payment logic that allows the model to choose a deficiency payment for RPS Program compliance, as established by the VCEA, if economically advantageous for customers compared to other options;
- Adjustments for excess RECs that can be sold to reduce customer cost;
- Included the options to purchase RECs from a Virginia REC market based on initial forecasted price assumptions received from ICF;
- Optimized generating unit retirement logic for least-cost modeling;
- Included a declining cost curve for solar and storage unit capital costs consistent with the NREL annual technology baseline assumptions for the moderate scenario, as discussed in Section 1.6, ***Commodity Price and Cost Assumptions***;
- Modeled distributed solar and all energy storage as combination units that reflect the costs of 65% Company-owned resources to 35% PPAs;

- Re-optimized the model for the cost sensitivities presented in Figure 2.6.3, rather than locking down the base case build plan; and
- Modeled named solar units at the lower of the design capacity factor or the three-year average of the Company's existing solar facilities in Virginia.

The Company will continue to refine its modeling as additional functionality becomes available in PLEXOS. The Company notes that REC banking remains unavailable in PLEXOS at this time.

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Chapter 5: Generation – Supply-Side Resources

This chapter provides an overview of the Company's existing supply-side generation, the generation resources under construction or development, and the Company's analysis of future supply-side generation. This chapter also provides a discussion of challenges related to the development of significant volumes of solar resources.

5.1 Existing Supply-Side Generation

5.1.1 System Fleet

Figure 5.1.1.1 shows the Company's 2022 capacity resource mix by unit type.

Figure 5.1.1.1 – 2022 Capacity Resource Mix by Unit Type

Generation Resource Type	Net Summer Capacity (MW)	Percentage (%)
Coal	3,680	17.9%
Nuclear	3,348	16.2%
Natural Gas	8,392	40.7%
Pumped Storage	1,808	8.8%
Oil	1,373	6.7%
Renewable	903	4.4%
PPA-Other	179	0.9%
PPA- Hydro	5	0.0%
PPA- Solar	921	4.5%
PPA- Contracted	1,105	5.4%
Company Owned	19,504	94.6%
Company Owned and PPA Contracted	20,609	100.0%
Purchases	0	0.0%
Total	20,609	100.0%

Due to differences in operating and fuel costs of various types of units and in PJM system conditions, the Company's energy mix is not equivalent to its capacity mix. The Company's generation fleet is dispatched by PJM within PJM's larger footprint, ensuring that customers in the Company's service territory receive the economic benefit of all resources in the PJM power pool regardless of the source. PJM dispatches resources within the DOM Zone from the lowest cost units to the highest cost units, while maintaining its mandated reliability standards. Figures 5.1.1.2 and 5.1.1.3 provide the Company's 2022 actual capacity and energy mix.

Figure 5.1.1.2 – 2022 Actual Capacity Mix

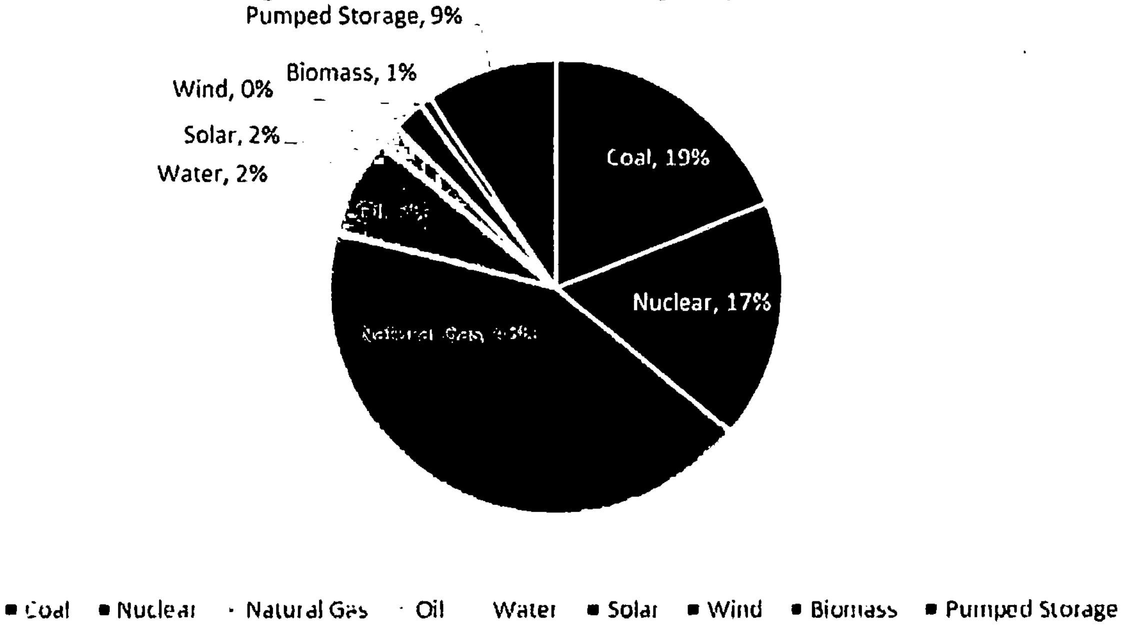
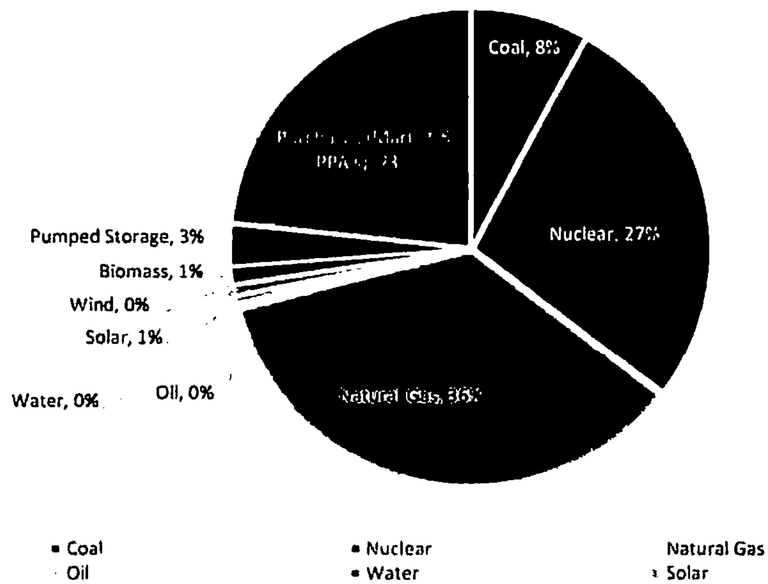


Figure 5.1.1.3 – 2022 Actual Energy Mix



Appendices 5A through 5E provide basic unit specifications and operating characteristics of the Company's supply-side resources, both owned and contracted. Appendix 5F provides a summary of the existing capacity by fuel class. Appendices 5G and 5H provide energy generation by type and by the system output mix. Appendix 5I provides a list of all Company-build or third-party PPA solar and wind generating facilities placed in service, under construction, or under development since July 1, 2018. Appendix 5O provides a list of renewable energy resources, and

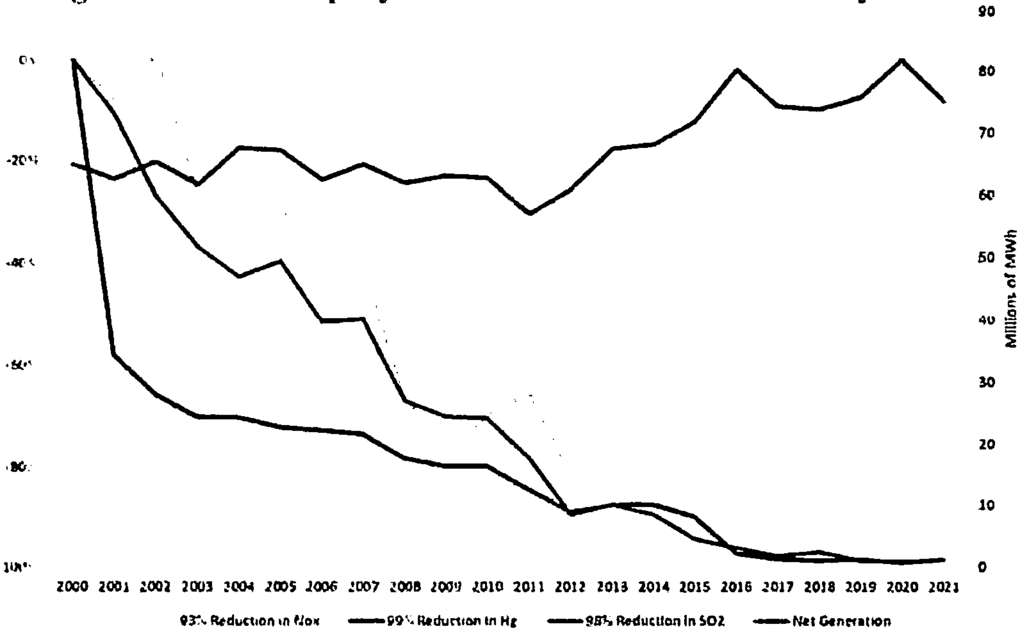
Appendix 5P provides a list of potential supply-side resources. Appendices 5Q and 5R present the Company's summer capacity position and seasonal capability, respectively. Appendix 5S provides the construction cost forecast for Alternative Plan B.

5.1.2 Company-Owned System Generation

The Company's existing system generating resources are located at multiple sites distributed throughout its service territory. This diverse fleet of 91 generation units includes 4 nuclear, 8 coal, 9 combined-cycles ("CCs"), 40 CTs, 3 biomass, 1 heavy oil, 6 pumped storage, 1 battery storage, 9 hydro, 1 offshore wind, and 9 solar with a total summer capacity of approximately 21,713 MW. For details on the Company's existing generating resources, see Appendix 5A. The Company currently owns and operates 903 MW of renewable energy resources, including solar, wind, hydroelectric, storage, and biomass, with an additional 200 MW (nameplate) under construction. The Company also owns and operates four nuclear facilities (3,349 MW), providing significant zero-carbon generation for its customers.

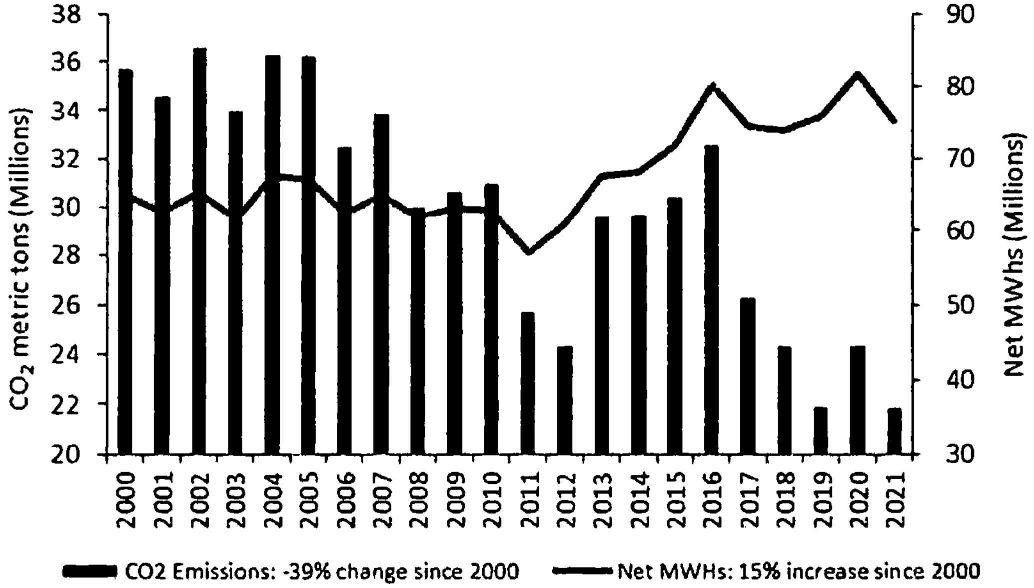
Over the past two decades, the Company has made changes to its generation mix that have significantly improved environmental performance. These changes include the retirement of certain units, the conversion of certain units to cleaner fuels, the conversion to dry ash handling, and the addition of air pollution controls. This strategy has resulted in significant reductions of air pollutants such as NOx, sulfur dioxide ("SO_2"), and mercury ("Hg"), as shown in Figure 5.1.2.1, and has also reduced the amount of coal ash generated and the amount of water used.

Figure 5.1.2.1 – Company Annual Reduction in Emissions by Percent



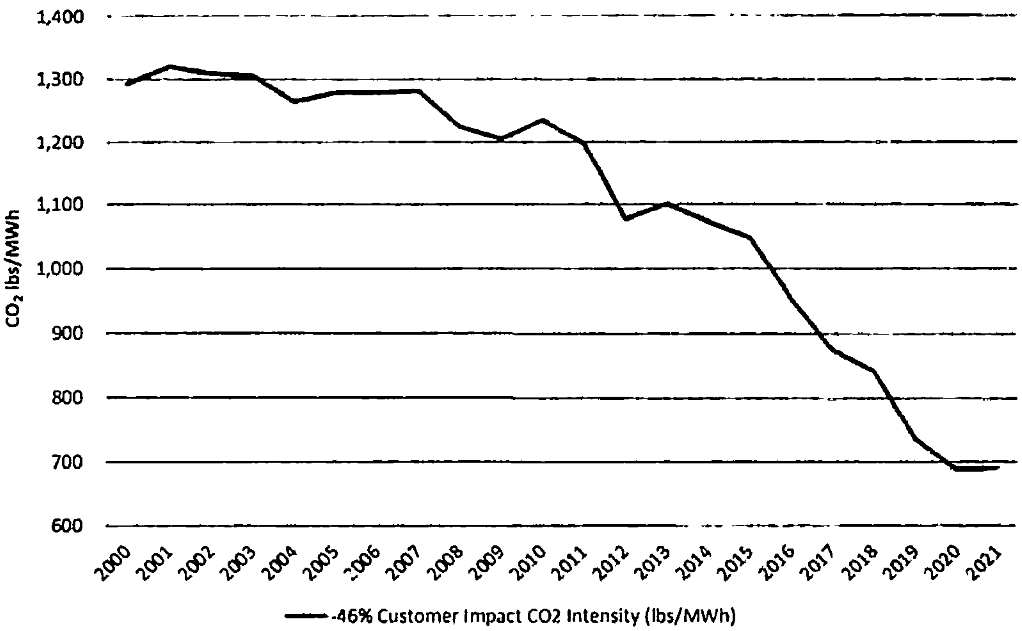
The Company develops a comprehensive greenhouse gas inventory annually. The Company's direct CO_2 emissions (based on ownership percentage) were 21.8 million metric tons in 2021 compared to 24.3 million metric tons in 2020. The Company has been a leader in reducing CO_2 emissions through retiring certain units; building additional efficient and lower-emitting natural gas-fired power generating sources and carbon-free renewable energy sources, such as solar and wind; and maintaining its existing fleet of non-emitting nuclear generation. As shown in Figure 5.1.2.2, from 2000 through 2021, the Company has reduced the CO_2 emissions in tons from its power generation fleet serving Virginia jurisdictional customers by 39%, while power production has increased by 15%.

Figure 5.1.2.2 – Company CO_2 Mass Reductions versus Net Generation



The Company's integrated business strategy has also resulted in significant reduction in CO_2 emission intensity. CO_2 intensity is the amount of emissions per MWh delivered to customers. This calculation includes emissions from any source used to deliver power to customers, including Company-owned generation, PPAs, and net purchased power. As shown in Figure 5.1.2.3, customer impact CO_2 intensity has decreased by 46% since 2000.

Figure 5.1.2.3 – Customer Impact CO_2 Intensity



5.1.3 Power Purchase Agreements

A portion of the Company's load and energy requirement is supplemented with contracted PPAs. The Company has existing contracts with fossil-burning and renewable energy PPAs for capacity of approximately 1,164 MW (nameplate).

For modeling purposes, the Company assumed that its PPA capacity would be available as a firm generating capacity resource in accordance with current contractual terms. These PPA units also provide energy to the Company according to their contractual arrangements. At the expiration of these PPA contracts, these units will no longer be modeled as a firm generating capacity resource. The Company assumed that PPAs or any other non-Company owned resource without a contract with the Company are available to the Company at market prices; therefore, the Company's optimization model may select these resources in lieu of other Company-owned, supply, or demand-side resources should the market economics dictate. Although this is a reasonable planning assumption, parties may elect to enter future bilateral contracts on mutually agreeable terms. For potential bilateral contracts not known at this time, the market price is the best proxy to use for planning purposes.

5.2 Evaluation of Existing Generation

The Company continuously evaluates various options with respect to its existing fleet, cognizant of environmental regulations and other policy considerations.

5.2.1 Retirements

The VCEA mandates the retirement of carbon-emitting generation on a specific schedule unless the Company petitions and the SCC finds that a given retirement would threaten the reliability and security of electric services:

- Chesterfield Units 5 and 6 (coal) and Yorktown Unit 3 (heavy oil) by 2024; and
- All remaining generation units that emit CO_2 as a byproduct of combustion by 2045.

Chesterfield Units 5 and 6 and Yorktown Unit 3 are all scheduled to retire in May 2023. No generation from these units is shown in the plans presented. Retirement notification letters for these stations can be found in Appendix 2B. The Altavista, Hopewell, and Southampton biomass units are no longer retiring by 2028 in all Alternative Plans, and RECs generated by those units can be used for RPS compliance per pending legislation HB2026/SB1231. Separate from these mandates, and consistent with prior Plans, the Company completed two analyses related to retirement of existing units.

First, the Company completed a 10-year cash flow analysis focused on coal-fired, biomass-fired, and large combined-cycle generation facilities under market conditions. The Company evaluated 10-year cash flows under five scenarios using the Base Case commodity price forecast as an underlying market forecast. Unit NPVs were derived by comparing the unit costs, including operations and maintenance and capital, to the total forecasted unit benefits, consisting of energy and capacity revenues (and REC revenues where applicable) for the next 10 years based on the snapshot in time when the analysis was conducted. This analysis allows the Company to view each unit's near-term projected revenue and cost streams in one place, and to determine key drivers for unit profitability.

A positive NPV result indicates that the unit is currently better than market, while a negative value indicates the unit is currently worse than market. These results alone are not comprehensive and cannot exclusively be used to determine whether to continue to operate an existing unit. Other quantitative and qualitative considerations must be prudently factored into such determinations, such as remaining useful life, capacity and energy replacements, system reliability, fuel contracts, transmission system considerations, personnel, impact of continued operation of the unit(s) on the local economy, and environmental benefits, to name a few. The results of the 10-year cash flow analysis are included in Figure 5.2.1.1.

Figure 5.2.1.1: Ten-Year Cash Flow Analysis Results (NPV $ Million)

Units	2023 Plan A	2023 Plan B	Low Capacity Price	High Capacity Price	Est. T&D Impact
Clover 1 - 2	$52	$48	($23)	$110	$0
Mt Storm 1 - 3	$148	$126	($130)	$352	$6
VCHEC	($199)	($206)	($305)	($119)	$16.8
Altavista	$21	$20	$12	$27	$0
Hopewell	$34	$32	$25	$39	$0
Southampton	$36	$35	$27	$42	$0
Rosemary	($4)	($4)	($26)	$16	$0
Bear Garden	$570	$557	$454	$649	$6
Brunswick	$1,217	$1,186	$954	$1,391	$6.5
Chesterfield 7 - 8	$316	$305	$241	$362	$3
Gordonsville 1 - 2	$122	$118	$81	$150	$0
Greensville	$1,600	$1,562	$1,301	$1,792	$6.5
Possum Point 6	$410	$397	$302	$482	$11.7
Warren	$1,600	$1,568	$1,339	$1,771	$0

Note: "Est. T&D Impact" represents the approximate transmission and distribution upgrades that would be necessary to support the unit retirement. This avoided cost is not included in the NPVs shown.

Second, as directed by the SCC, the Company included the same unit-specific data for the units listed in Figure 5.2.1.1 in PLEXOS to allow the model to optimize endogenously the timing of unit retirements. The Company presents these results as part of Alternative Plans A through C, which shows all units running through the Study Period. While a few units had a negative value in the 10-year NPV analysis, all units are positive when reviewed over the 25-year planning horizon shown in Figure 5.2.1.2 and PLEXOS did not select to retire any units.

In Alternative Plans D and E, consistent with prior filings, the Company aimed to determine a glide path to continue to reliably serve customers through the transition to a cleaner energy fleet, taking into consideration components such as capacity factors, performance characteristics, including ramping time, fuel diversity and availability, maintenance requirements, and environmental regulations.

Figure 5.2.1.2: Twenty-Five-Year Cash Flow Analysis Results (NPV $ Million)

Units	2023 Plan A	2023 Plan B	Low Capacity Price	High Capacity Price
Clover 1 - 2	$423	$797	$563	$828
Mt Storm 1 - 3	$1,817	$3,763	$2,915	$3,876
VCHEC	$193	$792	$465	$835
Altavista	$104	$165	$138	$169
Hopewell	$120	$181	$157	$184
Southampton	$125	$186	$158	$190
Rosemary	$27	$35	($39)	$45
Bear Garden	$1,650	$2,440	$2,098	$2,486
Brunswick	$3,670	$5,456	$4,689	$5,559
Chesterfield 7 - 8	$989	$1,603	$1,389	$1,631
Gordonsville 1 - 2	$469	$775	$654	$791
Greensville	$4,692	$6,869	$6,007	$6,984
Possum Point 6	$1,344	$2,103	$1,788	$2,145
Warren	$4,114	$5,827	$5,068	$5,929

It is worth noting that a ten-year cash flow analysis is not the only deciding factor in retiring an existing resource. Modeling in this 2023 Plan is based on normal weather and models the complete system, which does not fully capture the value of a unit that may be based on location, fuel diversity, value in extreme weather scenarios, operational flexibility, and black start capability, among other factors.

The Company has not made any decision regarding the retirement of any generating unit other than Yorktown Unit 3 and Chesterfield Units 5 and 6. Accordingly, the inclusion of a unit retirement in this 2023 Plan should be considered as tentative, based only on a snapshot in time. The Company's final decisions regarding any unit retirement will be made at a future date. Appendix 5J lists the generating units considered for potential retirement in Alternative Plan B.

5.2.2 Uprates and Derates

Efficiency, generation output, and environmental characteristics of units are reviewed as part of the Company's normal course of business. Many of the uprates and derates occur during routine maintenance cycles or are associated with standard refurbishment. However, several unit ratings have been and will continue to be adjusted in accordance with PJM market rules and environmental regulations. Appendix 5K provides a list of historical and planned uprates and derates to the Company's existing generation fleet.

5.2.3 Environmental Regulations

There are several final, proposed, and anticipated U.S. Environmental Protection Agency ("EPA") regulations that will affect certain units in the Company's current fleet of generation resources. Appendix 5L shows regulations designed to regulate air, solid waste, water, and wildlife.

The following section outlines changes to various environmental regulations since the Company filed its 2020 Plan. The 2020 Plan contains a historical perspective on some of the environmental regulations discussed. ~~Appendix 5L shows regulations designed to regulate air, solid waste, water, and wildlife.~~

Carbon Regulations

Federal Carbon Regulation

The past decade has seen attempts at carbon regulation at the federal level. The Clean Power Plan, announced in 2015 by President Obama, sought to set limits on carbon emissions from power plants. In 2018, President Trump announced the Affordable Clean Energy Rule ("ACE Rule"), which repealed and replaced the Clean Power Plan with a rule that sought to set heat rate efficiency improvements and improved operating and maintenance practices. Both efforts, which were adopted by the EPA under Section 111(d) of the Clean Air Act, saw significant legal challenges.

On January 19, 2021, the D.C. Circuit Court vacated the ACE Rule. On June 30, 2022, the U.S. Supreme Court issued a decision in *West Virginia v. EPA* that limits the scope of the EPA's authority to control greenhouse gas emissions from existing power plants under Section 111(d). This decision will impact how greenhouse gas emissions can be regulated at existing power plants by the EPA in future rulemakings, absent action from Congress. The EPA retains the authority to regulate at the source by proposing mechanisms such as heat rate improvements, but the EPA no longer holds the authority to regulate GHG emissions limits from power production by requiring a shift in electricity production to cleaner renewable energy sources from certain fossil fuel-fired power generation sources. Put another way, the EPA remains empowered to regulate carbon at the power plant level, but not at the economy-wide or electric utility-wide level.

The EPA is currently working on a new set of guidelines to direct states in regulating GHGs from existing fossil-fuel fired generating units within their borders. According to current EPA guidance, the EPA intends to issue a proposed rule in spring 2023, with a final rule expected in spring 2024.

RGGI

Regional Greenhouse Gas Initiative ("RGGI") is a collaborative effort to cap and reduce CO_2 emissions from the power sectors of participating states. Virginia joined RGGI as of January 1, 2021, through regulations, referred to as the CO_2 Budget Trading Rule. As a result, the Company has been required to purchase CO_2 allowances to cover CO_2 emissions from its regulated emissions sources.

On January 15, 2022, Virginia Governor Youngkin issued Executive Order Number Nine ("EO9") Protecting Ratepayers from the Rising Cost of Living Due to the Regional Greenhouse Gas Initiative directing state agencies to take certain actions to "re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative and immediately begin regulatory processes to end it." On March 11, 2022, as directed by EO9, the Virginia Department of Environmental Quality issued a report that presented a path for Virginia to end its participation in RGGI; the report also included an evaluation of the cost and benefits of participation in RGGI in view of all applicable data.

The following section outlines changes to various environmental regulations since the Company filed its 2020 Plan. The 2020 Plan contains a historical perspective on some of the environmental regulations discussed. Appendix 5L shows regulations designed to regulate air, solid waste, water, and wildlife.

Carbon Regulations

Federal Carbon Regulation

The past decade has seen attempts at carbon regulation at the federal level. The Clean Power Plan, announced in 2015 by President Obama, sought to set limits on carbon emissions from power plants. In 2018, President Trump announced the Affordable Clean Energy Rule ("ACE Rule"), which repealed and replaced the Clean Power Plan with a rule that sought to set heat rate efficiency improvements and improved operating and maintenance practices. Both efforts, which were adopted by the EPA under Section 111(d) of the Clean Air Act, saw significant legal challenges.

On January 19, 2021, the D.C. Circuit Court vacated the ACE Rule. On June 30, 2022, the U.S. Supreme Court issued a decision in *West Virginia v. EPA* that limits the scope of the EPA's authority to control greenhouse gas emissions from existing power plants under Section 111(d). This decision will impact how greenhouse gas emissions can be regulated at existing power plants by the EPA in future rulemakings, absent action from Congress. The EPA retains the authority to regulate at the source by proposing mechanisms such as heat rate improvements, but the EPA no longer holds the authority to regulate GHG emissions limits from power production by requiring a shift in electricity production to cleaner renewable energy sources from certain fossil fuel-fired power generation sources. Put another way, the EPA remains empowered to regulate carbon at the power plant level, but not at the economy-wide or electric utility-wide level.

The EPA is currently working on a new set of guidelines to direct states in regulating GHGs from existing fossil-fuel fired generating units within their borders. According to current EPA guidance, the EPA intends to issue a proposed rule in spring 2023, with a final rule expected in spring 2024.

RGGI

Regional Greenhouse Gas Initiative ("RGGI") is a collaborative effort to cap and reduce CO_2 emissions from the power sectors of participating states. Virginia joined RGGI as of January 1, 2021, through regulations, referred to as the CO_2 Budget Trading Rule. As a result, the Company has been required to purchase CO_2 allowances to cover CO_2 emissions from its regulated emissions sources.

On January 15, 2022, Virginia Governor Youngkin issued Executive Order Number Nine ("EO9") Protecting Ratepayers from the Rising Cost of Living Due to the Regional Greenhouse Gas Initiative directing state agencies to take certain actions to "re-evaluate Virginia's participation in the Regional Greenhouse Gas Initiative and immediately begin regulatory processes to end it." On March 11, 2022, as directed by EO9, the Virginia Department of Environmental Quality issued a report that presented a path for Virginia to end its participation in RGGI; the report also included an evaluation of the cost and benefits of participation in RGGI in view of all applicable data.

On December 7, 2022, the Virginia Air Board approved the Notice of Intended Regulatory Action to move forward on the draft regulation to repeal Virginia's CO_2 Budget Trading Rule. In accordance with Executive Order 19, which is the Governor's process for developing and reviewing state agency regulations, other executive branches within the government have approved to move forward with the repeal. The proposed repealed regulation went out for public comment on January 30, 2023, and the public comment period closed on March 31, 2023. A public hearing was held on March 16, 2023. The exit from RGGI is expected to be completed by December 31, 2023.

New Source Performance Standards for Greenhouse Gas Emissions

In December 2018, the EPA proposed revised new source performance standards ("NSPS") for greenhouse gas emissions from new, modified, and reconstructed stationary sources under Section 111(b) of the Clean Air Act. This action was never finalized. The EPA is currently reevaluating the NSPS for new and modified sources including what is determined to be the best system of emission reduction. A draft rule is expected in spring 2023. According to the EPA's unified agenda, the expected timeframe on a final rule is the second quarter of 2024.

Proposed Revisions to the Prevention of Significant Deterioration and New Source Review Regulations for Greenhouse Gases

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a prevention of significant deterioration permit for greenhouse gas emissions is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the new source review program and exceed a significant emissions rate of 75,000 tons per year of CO_2 equivalent emissions. There is no expected timeframe for the final rule.

New Proposed Federal Vehicle Emission Standards

On April 12, 2023, the EPA proposed new vehicle standards for light, medium and heavy-duty vehicles for model year 2027 and beyond. The EPA's proposal increases the stringency of the standard year-over-year on a phase-in approach. Through 2055, the EPA projects that the proposed standards would avoid nearly 10 billion tons of CO_2 emissions. The light and medium duty vehicle proposed standards are expected to avoid 7.3 billion tons of CO_2 emissions through 2055 and would also deliver significant health benefits by reducing fine particulate matter. The heavy-duty truck proposal is projected to avoid 1.8 billion tons of CO_2 through 2055.

Ozone National Ambient Air Quality Standards

The ozone national ambient air quality standard ("NAAQS") governs ground-level ozone forming pollutants, including NO_x emissions. The Clean Air Act requires the EPA to review the NAAQS every five years and revise the NAAQS if necessary.

On March 15, 2023, the EPA released a pre-publication of the final federal implementation plan ("FIP") addressing interstate transport for the 2015 Ozone NAAQS. The FIP is intended to resolve the good neighbor obligations with respect to the 2015 NAAQs. Virginia and West Virginia are covered in the FIP. The FIP consists of a combination of methods including a revised Cross-State Air Pollution Rule ("CSAPR") ozone season NO_x emissions trading program with additional restrictions not included in any of the current CSAPR trading programs. Coal-fired electric generating units (excluding circulating fluidized bed boilers) would be subject to daily emission rate limits during ozone season and would have to surrender additional allowances (at a 3:1 ratio), if limits are exceeded after the first 50 tons during the control period.

On December 31, 2020, the EPA published a final decision retaining the 2015 NAAQs of 70 parts per billion ("ppb") as the 2020 NAAQS. As directed by Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," signed by President Biden on January 20, 2021, the EPA undertook a review of the December 2020 decision that retained the 2015 NAAQs. As part of this reconsideration, the EPA is developing a policy assessment to consider all policy-relevant information developed throughout the 2020 review, and to engage with the Clean Air Scientific Advisory Committee Ozone Review Panel. The panel is currently reconsidering the decision to retain the 2015 NAAQs for ozone at 70 ppb for both the primary and secondary limits. According to the EPA's unified agenda, the EPA aims to issue a draft ruling in the second quarter of 2023 and a final rule by the end of 2023.

<u>**Particulate Emission Standards**</u>
On January 6, 2023, the EPA released a pre-publication version of a proposed rule resulting from its reconsideration of the primary (health-based) NAAQS for particulate matter ("PM NAAQS"). The EPA is proposing to lower the primary annual $PM_{2.5}$ NAAQS from 12.0 micrograms per cubic meter ("ug/m^3") to a level that would fall between 9.0 and 10.0 ug/m^3, while soliciting comment on an alternative annual $PM_{2.5}$ standard within the range of 8.0 to 11.0 ug/m^3. The EPA is proposing to retain the other PM NAAQs at their current levels, including the secondary 24-hour $PM_{2.5}$ NAAQS. According to the EPA's unified agenda, a final rule is expected in the third quarter of 2023.

<u>**Mercury & Air Toxics Standards**</u>
On March 6, 2023, EPA published a final rule that reinstates the Agency's April 25, 2016 finding that it is appropriate and necessary to regulate hazardous air pollutants emissions from coal and oil-fired electric generating units under Section 112 of the Clean Air Act via the mercury and air toxics standards ("MATS") rule. All of the Company's applicable units are complying with the applicable requirements of the MATS rule.

On April 24, 2023, the EPA published a proposal to tighten certain aspects of the MATS rule which include a lower emission limit for filterable particulate matter and required use of continuous emission monitoring system to demonstrate compliance with the PM limit. Other proposed changes include removal of emission limits for total and individual non-mercury hazardous air pollutants, and elimination of a "startup" definition. The EPA is expecting to come out with a final action by the end of 2023, with the final strategy and implementation likely occurring in the second quarter of 2024.

<u>**Coal Combustion Residuals**</u>
The Company currently operates inactive ash ponds, existing ash ponds, and coal combustion residual ("CCR") landfills at eight different facilities. In April 2015, the EPA enacted a final rule regulating (i) CCR landfills; (ii) existing ash ponds that still receive and manage CCRs; and (iii) inactive ash ponds that do not receive, but still store, CCRs. This rule created a legal obligation for the Company to retrofit or close all inactive and existing ash ponds over a certain

period of time, and to perform required monitoring, corrective action, and post-closure care activities as necessary. Since the rule was enacted, the EPA has reconsidered portions of the rule in response to litigation and petitions for reconsideration. In July 2018, the EPA promulgated the first phase of changes to the CCR rule and continues to issue changes to the CCR rule. In August 2018, the D.C. Circuit Court issued a decision in the pending challenges of the CCR rule, vacating and remanding to the EPA three provisions of the CCR rule. The Company does not expect the scope of the D.C. Circuit Court's decision to affect its closure plans.

Clean Water Act

The Clean Water Act ("CWA") is a comprehensive program that uses a broad range of regulatory tools to protect the waters of the United States, including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms.

Section 316(b)

In October 2014, the final regulations under Section 316(b) of the CWA became effective; these regulations govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold. The rule establishes a national standard for impingement based on seven compliance options but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two million gallons per day ("MGD"), with a heightened entrainment analysis for those facilities over 125 MGD.

The Company currently has seven facilities that are subject to the final Section 316(b) regulations. Additionally, the Company may have one hydroelectric power facility subject to the final regulations. The Company anticipates that it may have to install impingement control technologies at certain of these stations that have once-through cooling systems. The Company is currently evaluating the need or potential for entrainment controls under the final rule; decisions will be made on a case-by-case basis after a thorough review of detailed biological, technology, cost, and benefit studies.

Effluent Limitation Guidelines

In September 2015, the EPA revised its effluent limitations guidelines ("ELG") for the steam electric power generating category. The final rule established updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required to (i) convert from wet to dry or closed cycle coal ash management, (ii) improve existing wastewater treatment systems, and/or (iii) install new wastewater treatment technologies in order to meet the new discharge limits. In April 2017, the EPA granted two separate petitions for reconsideration of the ELG rule and stayed future compliance dates in the rule. In September 2017, the EPA signed a rule to postpone the earliest compliance dates for certain waste streams regulations in the ELG rule from November 2018 to November 2020. However, the latest date for compliance with the regulation remained December 2023.

In October 2020, the EPA published a revised ELG rule that included changes in the requirements for two waste streams, flue gas desulphurization ("FGD") and bottom ash transport waters ("BATW"), applicable to the Chesterfield Power Station and Mount Storm Power Station, respectively. The 2020 ELG rule also extended the compliance deadlines for final compliance with these requirements to December 2025 and offered an extended compliance deadline of December 2028 for facilities choosing to meet restrictive discharge limits or electing to cease coal combustion by that date. The Company is constructing BATW treatment facilities at Mt. Storm Power Station designed to comply with the 2020 ELG rule BATW requirements by March 31, 2024. In addition, the Company will be retiring the last coal-fired generating units at the Chesterfield Power Station during 2023.

On January 20, 2021, President Biden signed Executive Order 13990 directing federal agencies to review rules issued in the prior four years that are, or may be, inconsistent with the President's stated environmental policy. On July 26, 2021, the EPA announced that it was initiating a rulemaking process to determine whether to adopt more stringent limitations than those in the 2020 ELG rules for steam electric generating units. Subsequently, in March 2023, the EPA released a pre-publication version of proposed revisions to the 2020 ELG rule that includes discharge prohibitions on FGD and BATW waste streams. The BATW technology being installed at Mt. Storm Power Station has been designed to comply with the BATW discharge prohibition should it be promulgated. Retirement of the coal-fired generating units at Chesterfield Power Station eliminates any impact of this proposed rule to that station's discharges.

5.2.4 Nuclear License Extensions

The licenses to operate the two nuclear units at the Company's Surry Power Station were renewed by the NRC on May 4, 2021, permitting continued operation through 2052 for Unit 1 and through 2053 for Unit 2. The Company is now completing the upgrades deemed necessary to operate these units in the extended period of operations.

The Company submitted its application to the NRC to renew the licenses for its two units at the North Anna Power Station in August 2020. After the submittal, the Company engaged with the NRC, consultants, and industry partners regarding additional information requested for the application related to certain potential environmental impacts of operating North Anna Units 1 and 2 from 60 to 80 years. The Company submitted supplemental environmental information to the NRC on September 28, 2022. The NRC provided a schedule with application milestones moving forward that reflects an expected decision in July 2024, without intervenors filing contentions. The Company remains confident that it will receive the renewed licenses for these units, which would permit North Anna Units 1 and 2 to continue operating until 2058 and 2060, respectively.

In July 2022, the SCC approved the Company's request for cost recovery related to (i) preparing the subsequent license renewal applications and (ii) upgrading or replacing systems and equipment deemed necessary to operate safely and reliably in the extended period of operation. Based on this approval and the approval / anticipated approval of the subsequent license renewal application by the NRC, all Alternative Plans in this 2023 Plan assume that an additional 20 years will be added to the licenses at both the Surry and North Anna Power Stations.

5.3 Generation Under Construction

See Appendix 3A provides for details on the generation project under construction that the SCC has approved.

5.4 Generation Resources Under Development

The Company currently has solar, wind, energy storage, and CT generation projects under development, along with an LNG facility at one of the Company's existing units. The following sections provide details on these projects, as does Appendix 3B.

The Company has paused material development activities for North Anna 3 following receipt of the combined operating license ("COL") in 2017. The Company is currently incurring minimal capital costs associated with North Anna 3 specific to the administrative functions of maintaining the COL.

5.4.1 Solar, Onshore Wind, and Energy Storage

As part of its on-going efforts to expand the portfolio of renewable energy and carbon-free resources, and to meet the development targets as set forth in the VCEA, the Company has pursued multiple avenues to identify viable projects. The Company annually issues an RFP for new solar (utility-scale and distributed), energy storage, and onshore wind resources, seeking both projects for the Company to acquire and projects for the Company to purchase the output through PPAs. The Company also has sourced projects from outside the RFP process, which have traditionally come in the form of either self-development or bilateral transactions. The Company evaluates all potential projects and PPAs on an equal basis to determine which projects provide the best value for customers. As required by the VCEA, the Company then brings new Company-owned and PPA resources before the SCC for approval as part of its annual plan regarding the development of solar, onshore wind, and energy storage.

5.4.2 Combustion Turbines

Combustion turbines provide firm energy during periods of high demand to ensure grid reliability while supporting the growth of renewable energy resources specifically during periods when intermittent resources are not generating. Dispatchable energy generation will be critical to fill the gaps created when the production from intermittent generation drops but significant load continues. For example, as discussed above in Section 1.3, ***Severe Weather Events***, Winter Storm Elliott showed the need for every generating unit in the Company's fleet to be dispatched to meet the system peak early in the morning when solar resources were not producing energy. This type of extreme weather event threatens system reliability and requires resources to ensure the Company can meet customer demands. As discussed in Section 1.1, ***PJM Load Forecast and Energy Transition Risks***, PJM has specifically identified critical concerns associated with maintaining reliability during the transition to a system built on clean energy resources. CTs provide the capability to quickly dispatch when needed, with a proven history of being highly available, running reliably, and having the ability to provide energy over a longer period of demand. Combustion turbines also can help to address probable transmission system reliability issues resulting from the addition of significant renewable energy resources and the retirement of coal-fired facilities that are discussed further in Section 7.5, ***Transmission System Reliability Analyses***, including support for system restoration by providing black start capabilities.

For these reasons, the Company is evaluating sites and equipment for the construction of gas-fired CT units. These new combustion turbines will be dual-fuel capable, have additional onsite backup fuel supply, and be capable of blending hydrogen in the future. Multiple fueling capabilities provide flexibility to endure multi-day extreme weather events when gas supply is limited. Combustion turbines also support system restoration by providing black start capabilities. In order to meet the energy and capacity needs associated with the load forecast and without a commercially viable carbon-free, dispatchable generation alternative, CTs will be the critical component to ensuring grid reliability in the near term.

5.4.3 LNG Facility at Greensville

Greensville County Power Station provides essential, around-the-clock power with the ability to serve more than 350,000 Virginia homes. To maintain a readily available, reliable fuel source for this critical station and potentially others, the Company is proposing to add storage capabilities for LNG. This stored LNG will provide a reliable backup fuel supply to keep gas flowing in the event of a natural disaster, extreme weather, or other fuel supply disruptions or constraints.

The need for this type of backup fuel supply is illustrated by fuel shortages that occurred in recent years, impacting millions of customers. For example, in May 2021, the Colonial Pipeline, which carries gasoline and jet fuel to the Southeastern United States, was shut down for five days due to a cyberattack, resulting in a fuel shortage that affected millions of consumers and airlines along the East Coast. As another example, in Texas in February 2021, extreme winter weather caused a significant portion of the state's electric generating capacity to fail when demand reached historic highs, an issue compounded by failures of the natural gas delivery system, resulting in rolling blackouts and impacting millions of people.

The addition of an LNG facility to support Greensville Power Station and potentially others will reduce the Company's reliance on a single gas pipeline, provide backup to support at least 1,588 MW of generating capacity, and support gas supply available to the Company's fleet. This facility is vitally important to the reliability and resilience of the Company's system.

5.5 Future Supply-Side Generation Resources

The process of selecting alternative resource types starts with the identification and review of the characteristics of available and emerging technologies, as well as any applicable statutory requirements. Next, the Company analyzes the current commercial status and market acceptance of alternative resources. This analysis includes determining whether particular alternatives are feasible in the short- or long-term based on the availability of resources or fuel within the Company's service territory or PJM. The technology's ability to be dispatched is based on whether the resource is able to alter its output up or down in an economical fashion to balance the Company's constantly changing demand and supply conditions. Further, analysis of the alternative resources requires consideration of the viability of the resource technologies available to the Company. This step identifies the risks that technology investment could create for the Company and its customers, such as site identification, development, infrastructure, and fuel procurement risks. The feasibility of both conventional and alternative generation resources is considered in utility-grade projects based on capital and operating expenses including fuel and O&M.

Further analysis is then conducted in PLEXOS to incorporate seasonal variations in cost and operating characteristics, while integrating new resources with existing system resources. This analysis more accurately matches the resources found to be cost-effective in this screening process. This PLEXOS simulation analysis further refines the Company's analysis and assists in selecting the type and timing of additional resources that economically fit the customers' current and future needs.

Figure 5.5.1 summarizes the supply-side resource types that the Company reviewed as part of the generation planning process.

Figure 5.5.1 - Alternative Supply-Side Resources

Resource	Unit Type	Dispatchable	Primary Fuel	Busbar Resource	PLEXOS Resource
Aero-derivative Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Battery Generic (30 MW) (4H)	Peak	Yes	Varies	Yes	Yes
Combined Cycle - 3X1	Intermediate/Baseload	Yes	Natural Gas	Yes	No
Combined Cycle - 2X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Cycle - 1X1	Intermediate/Baseload	Yes	Natural Gas	Yes	Yes
Combined Heat and Power	Peak	Yes	Varies	No	No
Waste Heat to Power	Peak	Yes	Varies	No	No
Combustion Turbine	Peak	Yes	Natural Gas	Yes	Yes
Fuel Cell	Baseload	Yes	Natural Gas	Yes	No
Nuclear Small Modular Reactor	Baseload	Yes	Uranium	Yes	Yes
Pumped Storage (300 MW)	Peak	Yes	Renewable	Yes	Yes
Solar	Intermittent	No	Renewable	Yes	Yes
Solar (Distributed)	Intermittent	No	Renewable	Yes	Yes
Wind - Offshore	Intermittent	No	Renewable	Yes	Yes
Wind - Onshore	Intermittent	No	Renewable	Yes	Yes
Energy Storage	Peak	Yes	Varies	Yes	No

5.5.1 Supply-Side Resource Options

The following sections provide details on certain newer supply-side resource options the Company has considered. See Section 1.4, ***Small Modular Reactors***, for additional details on small modular reactors as a supply-side option. Previous Plans provide additional details on the more proven technologies, including biomass, CCs, CTs, nuclear, and solar. In addition, Section 5.4, ***Generation Resources Under Development***, provides additional details on generation currently under development, including solar, energy storage, wind, CTs, and a backup LNG facility.

Aero-derivative Combustion Turbine

Aero-derivative CT technology consists of a gas generator that has been derived from an existing aircraft engine and used in an industrial application. Designed for a small footprint and low weight using modular construction, aero-derivative CTs utilize advanced materials for high efficiency and fast start-up times with little or no cyclic life penalty. Aero-derivative CTs have been designed for quick removal and replacement, allowing for fast maintenance, greatly reduced downtimes, and resulting in high unit availability and flexibility. This is a fast ramping and flexible generation resource that can effectively be paired with intermittent, non-dispatchable renewable resources, such as solar and wind. Modeling for Alternative Plan A included two aero-derivative options, a 40 MW unit and a 90 MW unit. While these units are more expensive on a $/kW basis than standard CTs, they may be needed in the future to provide regulation and reserves or in locations with limited CIRs.

Combined Heat and Power / Waste Heat to Power

Combined heat and power ("CHP") is the use of a power station to generate electricity and useful thermal energy from a single fuel source. CHP plants capture the heat that would otherwise be wasted to provide useful thermal energy, usually in the form of steam or hot water. The recovery of otherwise wasted thermal energy in the CHP process allows for more efficient fuel usage. CHP's reduction in primary energy use through fuel efficiency leads to lower greenhouse gas emissions.

Waste heat to power ("WHP") is a type of combined heat and power that generates electricity through the recovery of qualified waste heat resources. WHP captures heat byproduct discarded by existing industrial processes and uses that heat to generate power. Industrial processes that involve transforming raw materials into useful products all release hot exhaust gases and waste streams that can be captured to generate electricity. WHP is another form of clean energy production.

The Company will continue to track this technology and its associated economics based on site and fuel resource availability, but modeling resources in alternative plans is not feasible without a partner and specific location.

Energy Storage

The term "energy storage" applies to a diverse set of technologies that can store energy at one time and make it available at another time. The technologies range in size, cost, performance characteristics, and application. Energy storage can support the grid in several ways, including improved reliability, increased resiliency, and operational flexibility. Based on the most current information sourced from the EIA, the amount of utility-scale battery storage installed in the entire United States is just over 5,000 MW. Of those 5,000 MW, approximately 400 MW are located within the PJM region.

Until recently, energy storage resources have not been broadly deployed at utility scale, other than pumped hydroelectric storage. In addition to legislation in recent years supporting pumped storage, the GTSA established a pilot program to test different applications of storage, and the VCEA sets targets for the development of energy storage generally in Virginia to enhance the reliability and performance of the generation, transmission, and distribution systems. Incremental incentives were made available for energy storage projects through the federal enactment of the Inflation Reduction Act.

The Company has three BESS currently operational that were approved by the SCC under the GTSA pilot program, one to study solar plus storage, one to study the prevention of solar backfeeding onto the transmission grid at a specific substation, and a third to study storage as a non-wires alternative to reduce transformer loading at a specific distribution substation. The Company filed its first annual report on the pilot program with the SCC on March 31, 2023, in Case No. PUR-2019-00124, including lessons learned from constructing these three BESS. The Company is evaluating additional opportunities for this pilot program, including storage paired with direct current fast charging infrastructure for EVs and another potential project aimed at understanding the ability of storage to provide backup power and resiliency for the Company's customers. Under the GTSA, the Company will also seek opportunities to expand its understanding of non-lithium energy storage technologies by evaluating alternative forms of energy storage, including long duration storage, and establish projects to deploy those technologies where technically and economically feasible.

Separate from the GTSA pilot program, the SCC approved two Company-owned storage facilities (one of which is paired with a solar facility) in March 2022 and an additional stand-alone storage facility in April 2023, all of which are currently in various phases of construction. The SCC has also approved 3 PPAs for stand-alone storage resources and 2 PPAs for solar plus storage resources as prudent over the past two years.

The Company presents its plan for the development of additional energy storage resources in the annual proceeding required by Va. Code § 56-585.5, including its progress to date on energy storage development. See SCC Case Nos. PUR-2020-00134, PUR-2021-00146, and PUR-2022-00124 for more information on the Company's approach to energy storage. As stated in those plans, the Company intends to pursue additional energy storage resources, including opportunities to deploy energy storage as behind-the-meter incentives, non-wires alternatives programs, and peak demand reduction programs. See Section 8.5, ***Battery Storage Pilot Program***, for a description of what the Company has proposed related to energy storage as a non-wires alternative. The Company is also partnering with the Virginia Department of Emergency Management and All Hazards Consortium on a pilot program in support of the Federal Emergency Management Agency Building Resilient Infrastructure and Communities initiative to utilize mobile energy storage systems during emergencies for back-up power to critical locations.

<u>Fuel Cell</u>

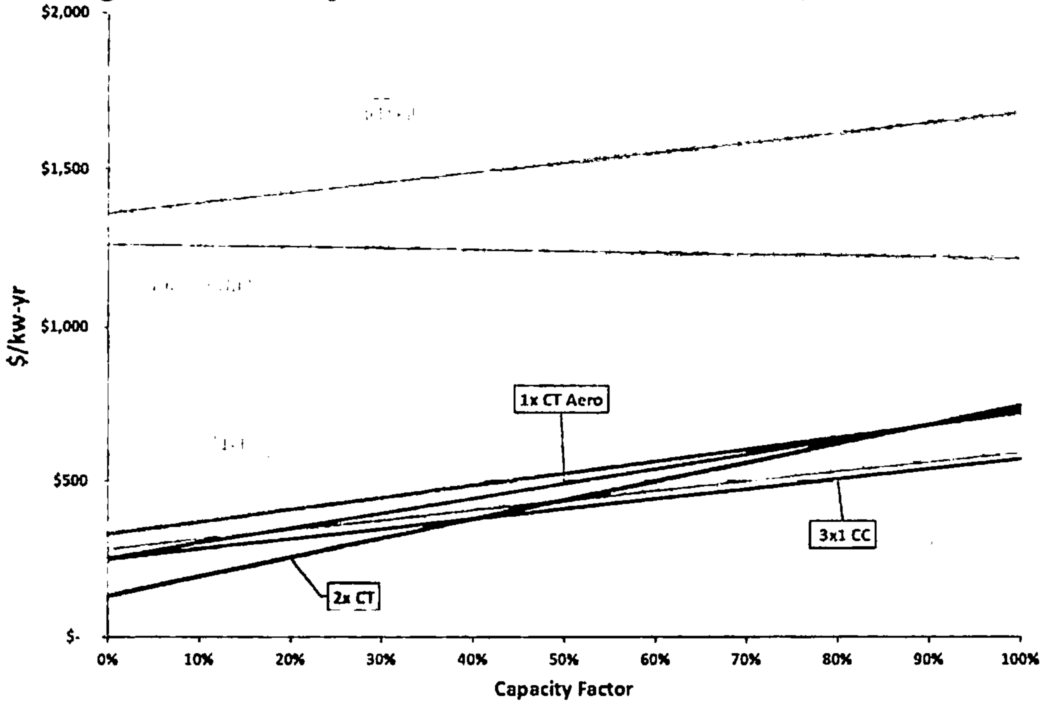
Fuel cells convert chemical energy from hydrogen-rich fuels into electricity and heat; there is no burning of the fuel. Fuel cells emit water and CO_2, resulting in power production that is almost entirely absent of NO_x, SO_x, or particulate matter. Similar to a battery, a fuel cell is comprised of many individual cells that are grouped together to form a fuel cell stack. Each individual cell contains an anode, a cathode, and an electrolyte layer. When a hydrogen-rich fuel, such as clean natural gas or renewable biogas, enters the fuel cell stack, it reacts electrochemically with oxygen (*i.e.*, ambient air) to produce electric current, heat, and water. While a typical battery has a fixed supply of energy, fuel cells continuously generate electricity as long as fuel is supplied. Fuel cells were invented in 1932 and put to commercial use by the National Aeronautics and Space Administration in the 1950s. They are now most common as a power source for buildings and remote areas, but continual improvements in technology are quickly bringing them into wider use.

5.5.2 Levelized Busbar Costs / Levelized Cost of Energy

The Company's busbar model was designed to estimate the levelized energy costs of various technologies on an equivalent basis. The busbar results show the levelized cost of power generation at different capacity factors and represent the Company's initial quantitative comparison of various alternative resources. These comparisons include fuel, heat rate, emissions, variable and fixed operation and maintenance costs, expected service life, overnight construction costs, and applicable REC investment or tax credits. These comparisons are also referred to as the levelized cost of energy or "LCOE".

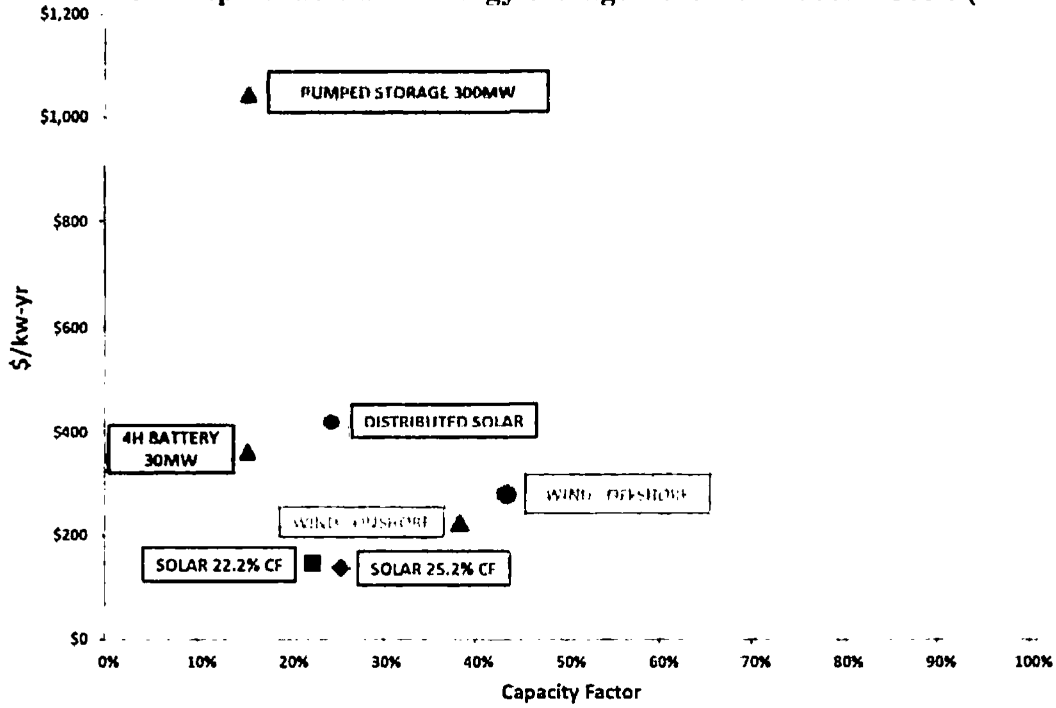
Figures 5.2.2.1 and 5.2.2.2 display high-level results of the busbar model, comparing the costs of the different technologies. The results were separated into two figures because non-dispatchable resources are not equivalent to dispatchable resources in terms of the energy and capacity value they provide to customers.

Figure 5.5.2.1 - Dispatchable Levelized Busbar Costs (2027 COD)



Notes: "CC" = combined-cycle; "CT" = combustion turbine; "CT Aero" = aeroderivative combustion turbine; "SMR" = small modular reactor

Figure 5.5.2.2 - Non-Dispatchable and Energy Storage Levelized Busbar Costs (2027 COD)



Note: "4H" = four hour; "CF" = capacity factor. Appendix 5M contains the tabular results of the screening level analysis. Appendix 5N displays the assumptions for heat rates, fixed and variable O&M expenses, expected service lives, and the estimated construction costs.

In Figure 5.5.2.1, the lowest values represent the lowest cost assets at the associated capacity factors along the x-axis. Therefore, one should look to the lowest curve (or combination of curves) when searching for the lowest cost combination of assets at operating capacity factors between 0% and 100%. Resources with LCOE above the lowest combination of curves generally fail to move forward in a least-cost resource optimization. Higher LCOE resources, however, may be necessary to ensure reliability and achieve other constraints such as those required by carbon regulations. Figures 5.5.2.1 and 5.5.2.2 allow comparative evaluation of resource types.

In Figure 5.5.2.1, the value of each cost curve at 0% capacity factor depicts the amount of invested total fixed cost of the unit. The slope of the unit's cost curve represents the variable cost of operating the unit, including fuel, emissions, and any REC or PTC or ITC value a given unit may receive.

Figure 5.5.2.2 displays the non-dispatchable and energy storage resources that the Company considered in its busbar analysis. Wind and solar resources are non-dispatchable with intermittent production and lower dependable capacity ratings. Both resources produce less energy at peak demand periods compared to dispatchable resources, requiring more capacity to maintain the same level of system reliability. Non-dispatchable resources may require additional grid equipment and technology changes in order to maintain grid stability.

As shown in Figure 5.5.2.1, CT technology is currently the most cost-effective option at capacity factors less than approximately 40% for meeting the Company's peaking requirements. The CC

3x1 technology is the most economical option for capacity factors greater than approximately 40%. As depicted in Figure 5.5.2.2, solar is a competitive choice at capacity factors of 22% to 25%.

The assessment of alternative resource types and the busbar screening process provides a simplified foundation in selecting resources for further analysis. However, the busbar curve is static in nature because it relies on an average of all of the cost data of a resource over its lifetime.

5.5.3 Third-Party Market Alternatives

During the last several years, the Company has increased its engagement of third-party solar developers in both its Virginia and North Carolina service territories.

In Virginia, the Company issues annual RFPs for solar, onshore wind, and energy storage resources, as discussed in Section 5.4.1, ***Solar, Onshore Wind, and Energy Storage***, and will continue to do so.

In North Carolina, the Company has signed 94 PPAs totaling approximately 722 MW (nameplate) of new solar PPAs. Of these, 696 MW (nameplate) are from 92 solar projects that were in operation as of December 2022. Most of these projects are qualifying facilities contracting to sell capacity and energy at the Company's published North Carolina Schedule 19 rates in accordance with the Public Utility Regulatory Policies Act.

5.6 Challenges Related to Significant Volumes of Solar Generation

All Alternative Plans in this 2023 Plan include significant development of solar resources, as shown in Section 2.2, ***Alternative Plans***. Based on current technology, challenges will arise as increasing amounts of these non-dispatchable, intermittent resources are added to the system. This section seeks to identify these challenges, which include intra-day, intra-month, and seasonal challenges posed by the interplay of solar generation and load, as well challenges related to system restoration. This section also discusses challenges related to constructing the level of solar generation as shown in the Alternative Plans. In this 2023 Plan, Alternative Plan B best addresses these challenges based on current technology. But the Company stands ready to meet these challenges with continued study, technological advancement, and innovation, and will provide the results of these advancements in future Plans and update filings.

Challenges Related to Capacity

- ELCC values of solar resources have been projected by PJM to drop significantly over time.
- The Company is not aware of any plans for non-Company load serving entities in the DOM Zone to secure additional generation. Historically, non-Company load serving entities in the DOM Zone have depended heavily on imported capacity from other zones.

Challenges Related to Energy

- The issues listed in ***Challenges Related to Capacity***, concerning non-LSE demand apply to energy supply as well.
- Solar generation experiences "non-normal" weather conditions throughout the year when output is significantly less than expected seasonal averages.

- The increased customer demand from data centers has a significantly different seasonal and time-of-day profile than planned solar generation.

Challenges Related to the Solar Production Profile

- The solar production profile is heavily biased towards the middle of the day and produces much less energy in the winter months.
- Heavy cloud cover tends to reduce solar production to a much greater extent than its impact to customer cooling demand.
- After periods of heavy snowfall, solar modules can take several days to get back to expected levels of production.

Challenges Related to Black Start and System Restoration

- At this point in time, solar generation would not be used for black start system restoration due to the impacts intermittent generation would have on grid stability during black start system restoration. Until there is sufficient energy storage to generate electricity at night and to mitigate the impacts of intermittent generation, solar generation will provide little to no value for black start purposes.

Challenges Related to Constructability

- Utility scale solar development requires significantly more land (per kW and per kWh) than any other technology.
- Solar development is most efficient from a kW/acre perspective with flat terrain and competes heavily with agricultural usage.
- Many Virginia communities have actively opposed large scale solar developments.

Chapter 6: Generation – Demand-Side Management

This chapter provides a description of the DSM planning process, and an overview of approved, proposed, and rejected DSM programs. See Section 4.1.3, ***Energy Efficiency Adjustment*** for discussion of how the Company adjusted the load forecasts used in this 2023 Plan to account for energy efficiency targets. This chapter also provides the energy efficiency-related analysis required by the GTSA.

There are several drivers that will affect the Company's ability to meet the current level of projected energy and demand reductions, including the cost-effectiveness of the DSM programs when filed, the SCC and NCUC approval of newly filed programs, the continuation of existing programs, the final outcome of proposed environmental regulations and customers' willingness to participate in approved DSM programs.

6.1 DSM Planning Process

The Company has historically used the following process related to its DSM programs:

The GTSA established the DSM stakeholder group, which helps to generate new program ideas. The Company takes those ideas and develops them into more concrete program parameters, which are then compiled into an RFP of candidate program designs and implementation services sent to qualified vendors. The Company develops assumptions for new DSM programs by engaging vendors through a competitive RFP process to submit proposals for candidate program design and implementation services. As part of the bid process, basic program design parameters and descriptions of candidate programs are requested. To the extent practical, the Company prefers that the program design vendor is the same vendor that implements the final implementation. The Company believes this enables as much continuity as possible from design to implementation.

Once proposals through an RFP process are received, the Company's energy conservation group works with the Company's supply chain group to systematically review the proposals. Program designs are reviewed for responsiveness to the RFP, practicality of the design, technology requirements, staffing plan, marketing plan, reasonableness of the measures proposed, overlap with existing measures, cost reasonableness, previous experience, work history with the Company, expected ability to deliver the services proposed, and ability of the proposing firm to comply with the Company's terms and conditions, data protection requirements, and financial requirements. Proposals must contain detailed information regarding measure load profiles and market penetration projections in a specific format which allows modeling of the program as a demand-side resource when compared against other resources, including supply-side resources.

Candidate designs that are judged to be reasonable, based on preliminary review, are evaluated for cost-effectiveness from a multi-perspective approach using four of the standard tests from the California Standard Practice Manual: (i) the Participant Test, (ii) Utility Cost Test, (iii) Total Resource Cost Test, and (iv) Ratepayer Impact Measure Test. Each test uses the NPV of costs and benefits. Tests are conducted at a program and portfolio level.

PLEXOS does not have the ability to conduct cost/benefit evaluations for DSM within the model itself, leading to the need for an additional model, tool, or process. For this reason, the Company has developed the Load Management Tool to perform the cost/benefits test leveraging the results obtained from PLEXOS. The inputs into the Load Management Tool are consistent with those in PLEXOS for the 2023 Plan. The Company looks at the results of all of the cost/benefit test scores, as well as NPV results, to evaluate whether to file for regulatory approval of a potential program, extension, or modification.

If the programs are cost-effective based on the modeling results, or otherwise legislatively stated to be in the public interest for policy reasons, the programs are then filed with the SCC for approval. The SCC approval process lasts approximately eight months. For the programs that are approved, the Company works with the RFP suppliers to finalize a contract for full implementation of the program. Once all details are finalized, a new DSM program can be launched for participation by eligible customers. Programs that meet the statutory criteria in Virginia are then, when feasible on a smaller scale, brought forth in the following year to the NCUC for consideration.

Finally, the Company conducts evaluation, measurement and verification ("EM&V") of all DSM programs and files the annual EM&V report with the SCC and NCUC each June for the prior calendar year on specific program metrics, including participation, spending, and energy and demand savings.

6.2 Approved DSM Programs

Appendix 6A provides program descriptions for the currently active DSM programs. Included in the descriptions are the branded names used for customer communications and marketing plans that the Company is employing and its plans to achieve each program's penetration goals. Appendices 6B, 6C, 6D, and 6E provide the system-level non-coincidental peak savings, coincidental summer peak savings, annual energy savings, and penetrations for each approved program.

The Company also currently offers one DSM pricing tariff, the standby generation ("SG") rate schedule, to enrolled commercial and industrial customers in Virginia and North Carolina. This tariff provides incentive payments for dispatchable load reductions that can be called on by the Company when capacity is needed. One customer is currently on the SG tariff in North Carolina and no customers participate in Virginia. The SG tariff provides a direct means of implementing load reduction during peak periods by transferring load normally served by the Company to a customer's standby generator. The customer receives a bill credit based on a contracted capacity level or the average capacity generated during a billing month when SG is requested. During a load reduction event, a customer receiving service under the SG rate schedule is required to transfer a contracted level of load to its dedicated on-site backup generator. Figure 6.2.1 provides estimated load response data for summer/winter 2022.

Figure 6.2.1 - Estimated Load Response Data

	Summer 2022		Winter 2022	
ariff	Number of Events	Estimated MW Reduction	Number of Events	Estimated MW Reduction
Standby Generation	19	2	0	0

The Company modeled this existing DSM pricing tariff over the Study Period based on historical data from the Company's customer information system. Projections were modeled with diminishing returns assuming new DSM programs will offer more cost-effective choices in the future.

6.3 Proposed DSM Programs

On December 13, 2022, the Company filed for SCC approval in Case No. PUR-2022-00210 for five new DSM programs (including one pilot) and four new program bundles as Phase XI programs:

- Residential Customer Engagement Program (EE)
- Residential Efficient Products Marketplace Program (EE)
- Residential Peak Time Rebate Program (DR)
- Non-Residential Custom Program (EE)
- Residential EV Telematics (Pilot Program)
- Residential Income and Age Qualifying Bundle Program (EE)
- Non-Residential Income and Age Qualifying Bundle Program (EE)
- Non-Residential Prescriptive Bundle Program (EE)
- Residential Home Retrofit Bundle Program (EE)

The SCC must issue its Final Order in Case No. PUR-2022-00210 in August 2023.

Appendix 6F provides program descriptions for the proposed DSM programs. Appendices 6G, 6H, 6I and 6J provide the system-level non-coincidental peak savings, coincidental peak savings, energy savings, and penetrations for each proposed program.

6.4 Future DSM Initiatives

The Company will be conducting an appliance saturation study in 2023 and, once completed, will begin a new DSM market potential study within the Company's service territory. This market potential study will provide additional guidance regarding what additional DSM measures are achievable.

During the first and second quarter of each year, the Company conducts an RFP process to solicit designs and recommendations for a broad range of DSM programs. The Company anticipates continuing this process for the foreseeable future. Within this process, detailed proposals are requested for programs that include measures identified in the most recent DSM potential study, as well as other potential cost-effective measures based upon current market trends.

Load conditions, energy prices, generation resource availability, and customer tolerance for the use of DSM are all important considerations for the Company in determining which DSM resources to deploy in the future. The use of these DSM resources largely depends on the circumstances and cannot be prescribed in any definitive manner. The Company will continue to identify and seek approval to implement DSM programs that are cost-effective or meet public policy goals.

As to cost-effective DSM available to respond to the growth of the winter peak, the Company's Distributed Generation Program is currently available to eligible non-residential customers in Virginia and provides dispatchable demand savings during winter periods to non-residential customers who meet participation requirements based upon size. The Company also offers a demand response residential smart thermostat control program, which also provides winter demand and energy savings. Further, the Company's other proposed DSM programs noted in Section 6.3, ***Proposed DSM Programs***, address both summer and winter peaks as well as energy requirements. While demand response programs can be used to reduce peak periods explicitly, energy efficiency programs can also provide reductions during winter hours. The Company is also actively involved with and participating in the DSM stakeholder process, as required by the GTSA and led by the SCC-appointed independent moderator, to further assist the Company in identifying potential opportunities for future energy efficiency and demand response programs and pilots. This effort will hopefully lead to future DSM initiatives that will address both summer and winter peak hours.

Appendices 6K and 6L provide the system-level coincidental peak savings and energy savings for the generic undesignated EE programs.

6.5 Rejected DSM Programs

A list of the rejected DSM programs from prior integrated resource planning cycles is shown in Appendix 6M. Rejected programs may be re-evaluated and included in future DSM portfolios.

6.6 GTSA Energy Efficiency Analysis

Enactment Clause 18 of the GTSA required, "That as part of its integrated resource plans filed between 2019 and 2028, any Phase II Utility, as that term is defined in subdivision A 1 of § 56-585.1 of the Code of Virginia, shall incorporate into its long-term plan for energy efficiency measures policy goals of reduction in customer bills, particularly for low-income, elderly, veterans, and disabled customers; reduction in emissions; and reduction in the utility's carbon intensity."

In its 2021 DSM filing, Case No. PUR-2021-00247, the Company filed a long-term plan for the Company's DSM initiatives with the end goal of setting forth an achievable strategy for meeting the VCEA energy efficiency targets, as well as the state energy and policy goals noted above. The long-term plan provides a vision and pathways for making every practicable effort to achieve the legislative goals over short-, medium-, and long-term time frames. The long-erm plan addresses: (i) strategic vision; (ii) achievability of GTSA and VCEA energy efficiency goals; (iii) risks, challenges, and opportunities stemming from legislative and regulatory changes; (iv) sector profiles, program design recommendations, and implementation pathways aligned with goals and high-level timelines; (v) approaches for adapting to an evolving customer market and advancements in technology; and (vi) high level forecast of energy and demand impacts, program costs, and cost-effectiveness.

The Company immediately began addressing the recommendations contained within the long-term plan and has made proposals to the SCC consistent with the recommendations therein as part of its filings for DSM Phases X and XI. The energy efficiency adjustments described above include the projected energy efficiency savings associated with the approved DSM Phase X, and the Phase XI savings will be incorporated into future Plans if approved by the SCC.

In particular, the Company notes that as part of its long-term plan for energy efficiency measures, the Company has projected spending at least 15% of all DSM-related spending on programs targeted towards low-income, elderly, and veteran populations. Indeed, the Company's DSM portfolio inclusive of Phase XI includes 15.4% of all DSM program costs designed to benefit vulnerable customers.

The continued implementation of the approved DSM programs will further carbon intensity reduction goals, reduce the number of RECs required for RPS compliance, and benefit participating customers through lower energy usage and resulting bills. The Company will continue to actively participate in the stakeholder forum, which provides transparency and inclusivity in the DSM planning process as part of its efforts to achieve the DSM policy goals set by the Commonwealth.

Enactment Clause 18 of the GTSA also directed that utility considerations of energy efficiency within its long-term plan shall include analysis of the following:

- Energy efficiency programs for low-income customers in alignment with billing and credit practices;
- Energy efficiency programs that reflect policies and regulations related to customers with serious medical conditions;
- Programs specifically focused on low-income customers, occupants of multifamily housing, veterans, elderly, and disabled customers;
- Options for combining distributed generation, energy storage, and energy efficiency for residential and small business customers;
- The extent that electricity rates account for the amount of customer electricity bills in the Commonwealth and how such extent in the Commonwealth compares with such extent in other states, including a comparison of the average retail electricity price per kWh by rate class among all 50 states;
- An analysis of each state's primary fuel sources for electricity generation, accounting for energy efficiency, heating source, cooling load, housing size, and other relevant factors; and
- Other issues as seem appropriate.

These items are addressed in the subsequent sections.

6.6.1 Considerations for Certain Customers Groups and Options for Combining Distributed Generation, Energy Storage, and Energy Efficiency

The Company's existing Residential Income and Age Qualifying Home Improvement Program provides in-home energy assessments and installation of select energy-saving products at no cost to eligible participants. The Program is available to qualified customers in the Company's Virginia service territory who earn 60% state median or area median income, whichever is higher. It is also available to customers who are 60 years or older with a household income of 120% of the state or area median income. The Program is available to qualified individuals living in single-family homes, multifamily homes, and mobile homes.

The Company also offers the House Bill 2789 (Heating and Cooling/Health and Safety) Program, which provides incentives for the installation of program measures that reduce residential heating and cooling costs and enhance the health and safety of residents, including repairs and improvements to home heating and cooling systems and installation of energy-saving measures in the house, such as insulation and air sealing. A companion program, the HB 2789 solar component, offers incentives to participants of the first component for the installation of photovoltaic solar panels at their residence. As with the Company's other low-income programs, the Company partners with Weatherization Service Providers ("WSP") to perform community outreach and install program measures to eligible customers.

Additionally, the Company offers certain EnergyStar measures such as EnergyStar appliances, EnergyStar ceiling fans, and EnergyStar windows to low-income customers. And, in its most recent DSM filing update in Case No. PUR-2022-00210, the Company proposed a bundled version of its income and age qualifying programs to ensure differing program offerings did not expire and to promote greater operational efficiencies with the WSP network in the field, which consists of non-profit providers performing the program field work and installing select energy-saving program measures. This regulatory matter is pending, with a final order expected in the latter part of summer in 2023.

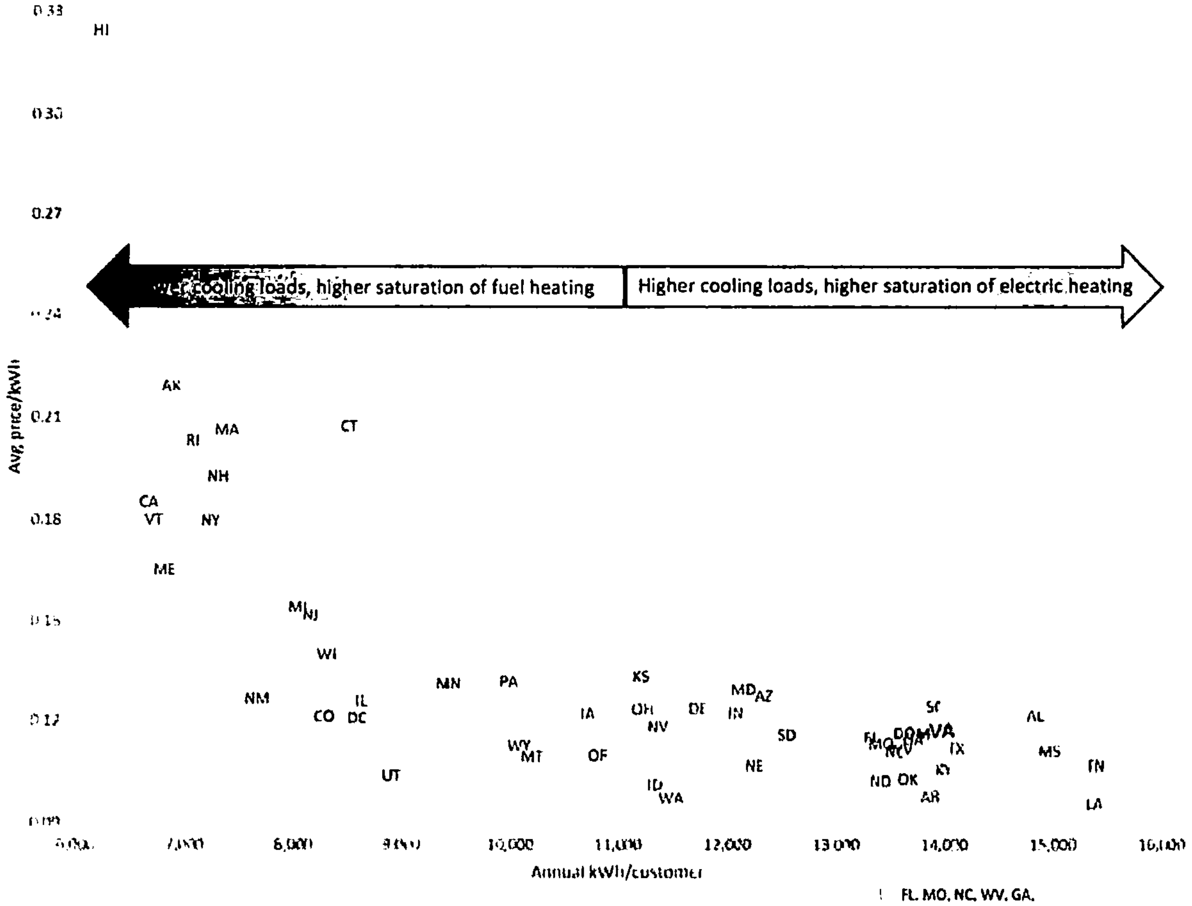
Separate from program proposals, a special subgroup focused on low-income DSM program improvements meets as part of the stakeholder process and making valued suggestions for future program improvements that will result in better alignment with the state's federally funded program. The Company has and will continue to work with the Department of Housing and Community Development to establish alignment with programs where helpful and beneficial.

6.6.2 Electricity Rate and Consumption Comparison

Electricity bills are driven by a combination of electricity rates and electricity consumption. The following charts show where each state and the Company falls by electricity rate and consumption.

In the residential sector, the Company and Virginia as a whole fall within a cluster of mostly southern states with below-average rates and relatively high consumption. The consumption level reflects a high saturation of electric heating equipment compared to other parts of the U.S., paired with high cooling loads.

Figure 6.6.2.1 – States by Residential Average Price per kWh and Consumption per Household

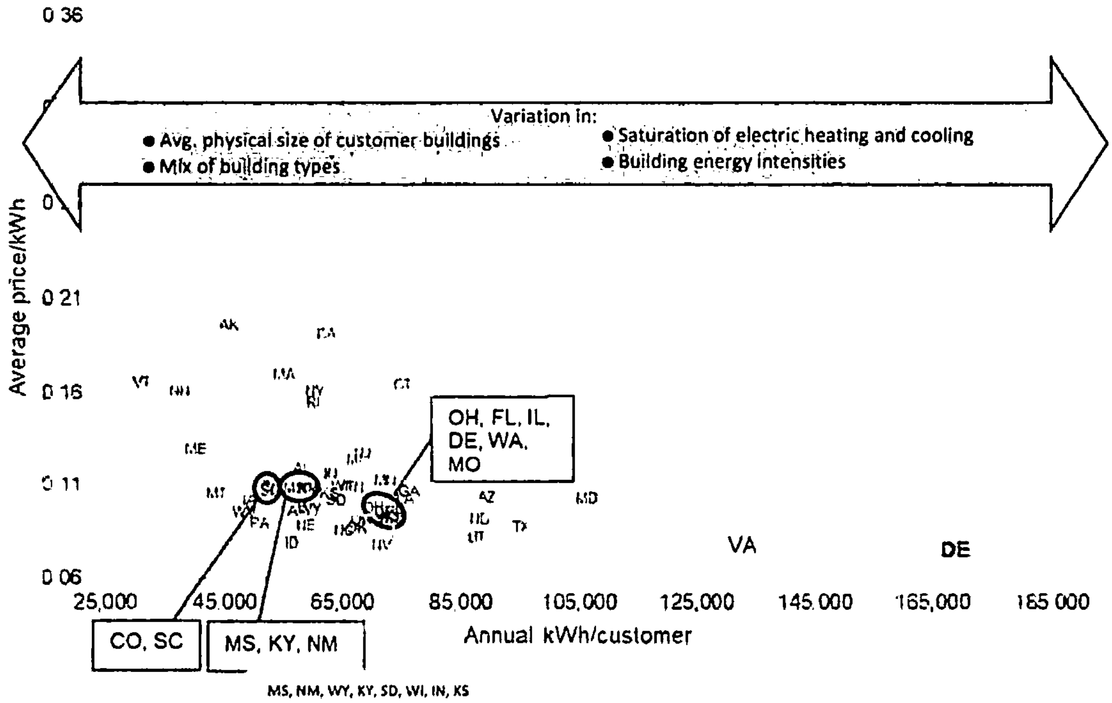


Notes: U.S. Energy Information Administration. Table 5A, Residential Average Monthly Bill by Census Division, and State (Annualized), https://www.eia.gov/electricity/sales_revenue_price/.
U.S Energy Information Administration, Annual Electric Power Industry Report, Form EIA-861 detailed data files, Year: 2021, https://www.eia.gov/electricity/data/eia861/.

In the commercial sector, Virginia is an extreme outlier in consumption per customer, averaging more than 130,000 kWh per year. The Company is one of three utilities in Virginia with average commercial consumption over 100,000 kWh per year; the others are the City of Harrisonburg, Appalachian Power Co., and Virginia Tech Electrical Services. In contrast, the utility with the lowest average commercial consumption is Northern Neck Elec Coop, Inc with less than 16,000 kWh per commercial customer.

The primary drivers of commercial consumption are the size of the customer (i.e., building square feet, number of employees) and the type of building activity. Denser urban areas tend to have larger commercial buildings and therefore higher average commercial consumption, and the Company's service territory captures many of Virginia's densest urban areas. The Company also has a high concentration of data centers among its commercial customers. Data centers are extremely energy intensive, as the densely packed computing equipment they contain produces waste heat that drives high space cooling loads. Because of the extreme differences among commercial customers, building efficiencies are typically compared based on energy intensity (*i.e.*, energy use per square foot) and only among similar building types (*i.e.*, offices with offices and restaurants with restaurants). Unfortunately, data was not available to calculate energy intensity for each state, or to make more granular comparisons.

Figure 6.6.2.2 – States by Average Commercial Price per kWh and Average Consumption per Commercial Customer



Note: U.S. Energy Information Administration. Table 5B. Commercial Average Monthly Bill by Census Division, and State (Annualized). https://www.eia.gov/electricity/sales_revenue_price/.

6.6.3 National Comparison of Primary Fuel Sources for Generation

The Company engaged DNV GL Energy Insights U.S.A. ("DNV GL") to analyze fuel source for generation, as well as the additional metrics referred to in the legislation. This analysis is provided in Appendix 6N.

6.6.4 Other Relevant Issues for Energy Efficiency Analysis

DNV GL, on behalf of the Company, also periodically assesses both the current stock of appliances through an appliance saturation study, and the potential for electric energy (kWh) and demand (kW) savings from Company-sponsored DSM programs through a market potential study of both residential and commercial customers. The most recent iteration of this process is currently underway, and results are expected by late 2023 or early 2024. The results will include:

- Estimates of the magnitude of potential savings on an annual basis;
- Estimates of the costs associated with achieving those savings; and
- Calculations of the cost-effectiveness of the measures based on the estimates above from a total resource cost perspective assuming PJM market price estimates.

part 4

Virginia State Corporation Commission
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The Company and DNV GL conducted previous market potential studies in 2015, 2017 and 2020. Appliance saturation studies and residential conditional demand analyses were conducted in 2013, 2016, 2019-2020, and included mail and electronic surveys of residential and commercial customers.

The market potential studies estimate three basic types of energy efficiency potential:

- Technical potential: The complete penetration of all measures analyzed in applications where they were deemed technically feasible from an engineering perspective.
- Economic potential: The technical potential of those energy efficiency measures that are cost-effective when compared to supply-side alternatives.
- Achievable program potential: The amount of savings that would occur in response to specific program funding, marketing, and measure incentive levels. In this study, the Company looked at the potential available under two funding scenarios—50% incentives and 75% incentives.

The Company, through its DSM stakeholder process, uses the information contained in the market potential studies to help develop ideas for potential DSM programs to include measures that may be cost beneficial. The most recent market potential study is typically released with a Company solicitation for DSM programs.

6.7 Overall DSM Assessment

In this 2023 Plan, there is a total reduction of 1,786 GWh by 2023 in DSM-related savings. By 2028, there are 3,696 GWh of reductions included in the PLEXOS modeling for this 2023 Plan. Projected energy savings include reductions from identified sources (*i.e.*, DSM programs approved by the SCC), as well as unidentified sources (*i.e.*, "generic" DSM as discussed in Section 4.1.3, ***Energy Efficiency Adjustment*** and below). For modeling purposes, neither the identified nor the unidentified sources included free-ridership effects. If these sources had included free-ridership effects, the reductions by 2023 and 2028 would be 1,858 GWh and 3,719 GWh, respectively. Projected savings attributable to DSM programs in 2028 are shown in Appendix 6O.

At the end of the Planning Period (*i.e.*, 2038), energy reductions projected for the identified DSM programs are approximately 1,468 GWh. This compares to 1,373 GWh identified in the 2020 Plan. Most of the increase in energy reductions is attributed to the additions of the Phase IX and Phase X programs. The capacity reductions at the end of the Planning Period for the identified DSM programs are 433 MW in this 2023 Plan. This compares to 383 MW in the 2020 Plan. Most of the increase in capacity reductions is attributed to the additions of the Phase IX and Phase X programs.

In this 2023 Plan, the unidentified DSM resources are presented as an unidentified generic block of energy efficiency reductions to meet the GTSA and VCEA requirements, as explained in Section 4.1.3, ***Energy Efficiency Adjustment***. That section also includes a discussion of the energy efficiency reductions used as adjustments to the load forecast in this 2023 Plan. Figures 4.1.3.1 and 4.1.3.2 show these energy efficiency energy and capacity adjustments, respectively.

Appendix 6P presents a comparison of the Company's expected demand-side management costs relative to expected supply-side costs. The costs are provided on a levelized cost per MWh basis for both supply- and demand-side options. The supply-side options' levelized costs are developed by determining the revenue requirements, which consist of the dispatch cost of each of the units and the revenue requirement associated with the capital cost recovery of the resource. The demand-side options' levelized cost is developed from the cost-benefit runs. The costs include the yearly program cash flow streams that incorporate program costs, customer incentives, and evaluation, measurement, and verification costs. The NPV of the cash flow stream is then levelized over the Planning Period using the Company's weighted average cost of capital. The costs for both types of resources are then sorted from lowest cost to highest cost and are shown in Appendix 6P.

Notably, the Company does not use levelized costs to screen DSM programs. DSM programs also produce benefits in the form of avoided supply-side capacity and energy cost that should be netted against DSM program cost. The DSM cost-benefit tests are the appropriate way to evaluate DSM programs when comparing to equivalent supply-side options and are the methods the Company uses to screen DSM programs.

Chapter 7: Transmission

This chapter provides an overview of the transmission planning process, as well as a list of current and future transmission projects. In addition, this chapter provides the results of the system reliability analyses performed to assess the potential effect of retiring all generating units that emit CO_2 as a byproduct of combustion by 2045.

7.1 Transmission Planning

The Company's transmission system is responsible for providing transmission service: (i) for redelivery to the Company's retail customers; (ii) to Appalachian Power Company, Old Dominion Electric Cooperative, Northern Virginia Electric Cooperative, Central Virginia Electric Cooperative, and Virginia Municipal Electric Association for redelivery to their retail customers in Virginia; and, (iii) to North Carolina Electric Membership Corporation and North Carolina Eastern Municipal Power Agency for redelivery to their customers in North Carolina (*i.e.*, collectively, the DOM Zone). Also, several independent power producers are interconnected with the Company's transmission system and are dependent on the Company's transmission system for delivery of their capacity and energy into the PJM market.

The Company is part of PJM, which is currently responsible for ensuring the reliability of, and coordinating the movement of, electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. The Company also is part of the Eastern Interconnection transmission grid, meaning its transmission system is interconnected, directly or indirectly, with all of the other transmission systems in the United States and Canada between the Rocky Mountains and the Atlantic Coast, except for Quebec and most of Texas. All of the transmission systems in the Eastern Interconnection are dependent upon each other for moving bulk power through the transmission system and for reliability support.

The Company's transmission system is designed and operated to ensure adequate and reliable service to customers while meeting all regulatory requirements and standards. Specifically, the Company's transmission system is developed to comply with the NERC Reliability Standards, as well as the Southeastern Reliability Corporation supplements to the NERC Standards. Federally mandated NERC Reliability Standards constitute minimum criteria with which all public utilities must comply as components of the interstate electric transmission system. Moreover, the Energy Policy Act of 2005 mandates that electric utilities follow these NERC Reliability Standards and imposes fines for noncompliance of approximately $1.3 million per day per violation.

The Company participates in numerous regional, inter-regional, and sub-regional studies to assess the reliability and adequacy of the interconnected transmission system. The Company is a member of PJM; PJM is registered with NERC as the Company's planning coordinator and transmission planner. Accordingly, the Company participates in the PJM regional transmission expansion plan ("RTEP") to develop the RTO-wide transmission plan for PJM.

The PJM RTEP covers the entire PJM control area and includes projects proposed by PJM, as well as projects proposed by the Company and other PJM members through internal planning processes.

The PJM RTEP process includes both a 5-year and a 15-year outlook. The Company is actively involved in supporting the PJM RTEP process.

The Company also evaluates its ability to support expected customer growth through its internal transmission planning process. The results of these evaluations indicate if any transmission improvements are needed, which the Company includes in the PJM RTEP process as appropriate. If the need is confirmed, then the Company seeks approval for the transmission improvements from the appropriate regulatory body.

Additionally, the Company performs seasonal operating studies to identify facilities in its transmission system that could be critical during the upcoming season. The Company coordinates with neighboring utilities to maintain adequate levels of transfer capability to facilitate economic and emergency power flows.

7.2 Existing Transmission Facilities

The Company has approximately 6,800 miles of transmission lines in Virginia, North Carolina, and West Virginia at voltages ranging from 69 kV to 500 kV. These facilities are integrated into PJM.

7.3 Transmission Facilities Under Construction

A list of the Company's transmission lines and associated facilities that are under construction can be found in Appendix 7A. Through participation in the PJM RTEP as well as regional, inter-regional, and sub-regional studies described in Section 7.1, ***Transmission Planning***, the Company annually assesses the reliability and adequacy of the interconnected transmission system to ensure the system is adequate to meet customers' electrical demands both in the near-term and long-term planning horizons.

7.4 Future Transmission Projects

Appendix 3C provides a list of planned transmission projects during the Planning Period, including projected cost per project as submitted to PJM as part of the RTEP process.

7.5 Transmission System Reliability Analyses

In 2020, the Company provided an initial overview of the reliability analyses that it would need to perform to investigate the probable system reliability issues resulting from the addition of significant renewable energy resources and the retirement of synchronous generators. The Company has included and will continue to include the up-to-date reliability analyses in its integrated resource plans and update filings.

Based on the time it takes to complete this type of analysis, the Company used preliminary versions of Alternative Plans A through E in this 2023 Plan and the 2022 PJM Load Forecast. The results and issues identified in this chapter are high level and preliminary, and the Company made several simplifying assumptions. As the contours of future technical challenges that the transmission system will encounter are identified and understood in greater detail, the Company will develop a comprehensive transmission plan that addresses them.

Overall, the results of the Company's analyses show that Alternative Plans D and E will severely challenge the ability of the transmission system to meet customers' reliability expectations. For example, prolonged cold weather or multiple days of clouds and rain will greatly challenge transmission system operators who must balance load and generation resources in real-time operations while also maintaining compliance with NERC reliability requirements. While the Company will be able to develop a transmission expansion plan that will allow for the reliable operation of the transmission system, Alternative Plans D and E would require an investment level that exceeds current transmission level expenditures and would likely exceed the future transmission level costs initially identified in the 2023 Plan.

The reliability analyses performed rely heavily on the capability to import power from PJM, but the reality is that all the Company's neighbors are facing the same generation challenges, meaning that importing power and energy at any time in a year will become more scarce. The Company will continue to study the scarcity of dependable resources within the PJM region as retirements are announced and the grid becomes increasingly reliant on renewable energy resources. In addition, given the significant increase in load in the 2023 PJM Load Forecast compared to the 2022 PJM Load Forecast, the potential reliability concerns identified are likely understated.

7.5.1 Inertia and Frequency Response

Electrical inertia is a system's capacity to resist changes in electrical frequency or frequency response, which is the real-time balance between generation and load. The electrical inertial response, or "inertial response," acts to overcome an immediate imbalance between power supply and demand. Electrical inertia directly relates to the reservoir of stored kinetic energy inherent to traditional rotating synchronous generators on the Company's system. Inertia allows the electric grid to control the frequency deviations that occur all the time, which are caused by events such as load changes, transmission and distribution outages, generation shedding, and system instability. Synchronously rotating machines provide a minimum critical level of inertia. Future technological advances will enable the inertia to be provided as "virtual inertia" by grid-forming inverters with rotating inertia behind them, such as wind turbines or battery storage systems. However, most of today's solar, wind, and storage inverters are of a grid-following type and cannot supply virtual inertia. This can lead to significant problems in managing system frequency, leading to a less reliable electric grid under the high penetration of inverter-based generation resources.

Accordingly, examining the synchronous inertial and frequency responses of the Company's system is critical because these two criteria provide insights into the power system's total frequency support. Theoretical and software simulation methods have been explored to examine these criteria and investigate which alternative plans can ensure acceptable frequency support. Analyzing inertial and frequency response for the DOM Zone depends on the PJM system's expected generation technology mix for the coming years.

The Company evaluated the expected generation technology mix shown in preliminary versions of Alternative Plans A through E in terms of installed capacity together with the installed reserves for the year 2027. Except for Alternative Plan A, which has a positive margin of 3,275 MW, Alternative Plan B through E had negative installed margins. Specifically, system net resources (*i.e.*, generation + storage – load – imports) decrease in the year 2027 by 4 to 7 GW and in the year 2035 by 5 to 8 GW as compared to the year 2021 in the 2022 PJM Load Forecast. The reduction in generation resources and the increase in electric demand will have a significant impact on system reliability; specifically related to less fault current and system inertia, and reduced import capabilities.

The data shows the deterioration of inertial response as the Company's system moves away from relying on large synchronous generation and imports for frequency regulation. This study verifies the system's inertia trend. The net-load imbalance must be met with imports scheduled ahead of time or in real time to ensure flexible reserves can adequately accommodate electricity demand shifts or generation changes from intermittent resources. However, the fast and primary frequency response study was simplified due to present-day simulation tools' limitations and available information. Specifically, a simplified model of the Company's system is represented as a single bus area connected to the PJM system through an equivalent intertie.

The inertial and primary frequency response of the DOM Zone to the loss of the Greenville Power Plant at 1,652 MW was analyzed for preliminary versions of Alternative Plans A through E and for each year between 2022 and 2036. The analysis was conducted at the two bookends of import capability, between (i) the Company and Eastern Interconnect—namely, fully interconnected at a 5,000 MW import capability—and (ii) the Company is islanded with a zero MW import. For Alternative Plan A, the frequency response measured by the expected rate of change of frequency is around 0.08 hertz per second ("Hz/s") when connected with the Eastern Interconnect and rises to 0.5 Hz/s when the DOM Zone is islanded; both did not exceed the highest acceptable threshold of 1 Hz/s. However, keeping minimum dispatchable resources online is not necessary if the Company's system is connected to PJM for Alternative Plans A through E.

PJM represents the non-dispatchable and intermittent resources with a dependable capacity rating in its FERC-approved RTEP planning process. This capacity rating is designed to match the average output of intermittent resources in PJM's load zones during peak summer loading conditions. However, it misses the range of conditions that the electric system may have to withstand, such as timeframes when intermittent generation output is close to 100% of its nameplate rating or during winter loading conditions when the solar generation output is close to zero. Additionally, the study assessed energy adequacy that characterizes the potential risk of load shedding under normal and extreme conditions over a year in order to capture the time sequence issues of the renewable energy output. The inertia and frequency response study analysis simulated several scenarios of renewable and load profiles using hourly resolution (*i.e.*, 8,760 analysis) considering transmission import capability under various likely system operating conditions.

The Company has historically relied on imports from the PJM system to serve the needs of the territory's load. However, the DOM Zone's import capability in the year 2027 under various contingency criteria (*e.g.*, N-1, and N-1-1) for three operating scenarios ranges between 1,077 MW in winter peak, 2,072 MW in summer peak, and 5,530 MW in shoulder scenarios. These import capability limits are significantly lower than the DOM Zone's historical import levels, which reached 6,000 MW. Once again, none of the generation portfolios shown in preliminary versions of Alternative Plans A through E have sufficient resources to serve the peak load without imports. The Company will continue to work and plan to PJM's load deliverability test to ensure the Company is providing adequate import capabilities to meet the customer's demand.

The DOM Zone will experience significant changes over the coming years: the peak load will increase, the synchronous generation will decrease, the import capability will decrease, and the energy storage will increase. The shift from a resource mix currently dominated by thermal, synchronous generation to one dominated by intermittent renewable generation in the next 10 to 15 years will challenge the Company's ability to meet demand around the clock with clean and reliable power. Combined with insufficient transmission import capability from PJM, these factors will reduce net dependable resources for Alternative Plans A through E, ranging between 4.5 to 7 GW by 2027 and 5.2 to 8 GW by 2035. A weaker transmission system does not provide adequate inertia or frequency to respond to or sustain faults on the grid which traditional rotating generation or synchronous condensers provide.

Notably, the situation becomes more challenging based on the higher load growth shown in the 2023 PJM Load Forecast when compared to the 2022 PJM Load Forecast. The Company will incorporate updated load forecast into its reliability analyses in future filings.

7.5.2 Short-circuit System Strength

A short circuit, also known as a fault, is a system disturbance, such as a tree branch falling across electrical lines. When these short-circuit events occur, quickly removing the faulted energized equipment from service is critical for (i) ensuring personnel and public safety, (ii) preventing or reducing equipment failure, and (iii) maintaining the electric grid's stability. Currently, protection and control systems—comprised of relays, circuit breakers, reclosers, and fuses installed across the entire system—remove equipment within milliseconds to seconds. In today's electric grid, a short circuit typically results in a spike in electrical current to that point and depressed voltage around the location of the fault. In a grid with a high density mix of transmission lines and synchronous generation the grid is considered strong and voltage recovers quickly from faults and disturbances enhancing the grid's stability. However, when the transmission and synchronous generation mix dissipates, the system becomes inherently weaker leading to a less stable system. Detection and quick recovery from disturbances occurs today because traditional rotating synchronous generators supply a significant amount of current during short-circuit events. The protection and control systems in operation today—across the entire system in generation plants, transmission and distribution substations, distribution circuits, and even inside customer facilities and homes—are all primarily designed to remove short-circuit events by detecting very high currents.

Inverter-based resources, such as solar and wind, do not provide any significant current increase during short-circuit events; rather, they provide either no change in current or only a nominal amount during short-circuit events. As traditional rotating synchronous generators are retired and replaced with inverter-based generation, the system will likely experience a fundamental change in short-circuit behaviors across all grid levels, specifically lowering short circuits' currents and strength. This will cause the Company's existing protection and control systems, which are installed across the entire system, to have major challenges in detecting these short-circuit events and protecting the system, personnel, and the public.

The short-circuit strength study started with modeling the future resource portfolio within the transmission grid using PJM's RTEP 2027 model, with a focus on the ability of the Company's system to integrate the inverter-based resources and the need for mitigations in the form of synchronous condensers. The effective short circuit ratio ("ESCR") was calculated at each inverter point of interconnection and compared to an acceptable threshold. ESCR was adopted for this study due to its ability to account for the impact of multiple inverter-based resources in close electrical proximity. The ESCR calculation utilized PJM's RTEP 2027 model with the following assumptions:

- Point of interconnection at each inverter-based resource is set to the nearest transmission bus (69 to 500 kV) in order to focus only on bulk system issues and not internal plant issues.
- Only inverter-based resources with grid-following inverters are considered.
- Stand-alone battery storage systems are assumed to have grid-forming inverters and thus are excluded from the analysis.

Based on this analysis, system short-circuit strength in 2027 is deficient at 29 points of interconnection in the Outer Banks and Virginia Beach subzones. Specifically:

- All 745 MW of inverter-based resources in the Outer Banks and Virginia Beach failed the test, while 54.7% of the 303 MW of inverter-based resources in Suffolk failed and 20.6% of the 2,147 MW of inverter-based resources in the PJM zone failed.
- If 388 MW of inverter-based resources are reduced, mainly in the Outer Banks, PJM, and Suffolk zones, the remaining inverter-based resources will pass the test.

To mitigate this problem, adding three synchronous condensers, such as SMRs or other rotating generation, totaling 800 MVA would improve ESCR, and all 6,779 MW of inverter-based resources would pass the test. Alternatively, reducing the solar and wind interconnections by 388 MW would mitigate the problem. As the generation mix changes, the Company will continuously reevaluate the system short-circuit strength and address as necessary.

7.5.3 System Restoration and Black Start Capabilities

Large-scale blackouts negatively impact the public, the economy, and the power system. A proper black start system restoration plan can help to restore power quickly and effectively. Black start—which restores electric power stations and the electric grid without relying on external connections—is the most critical scenario for system restoration. A black start unit is a generator that can start from its own power without support from the power grid, which is essential in the event of a major system collapse or a system-wide blackout. Black start units, and the generation included in the system restoration plan, must be available 24/7 and must have constant and predictable output when operational. These requirements provide difficulties for solar- and wind-generation resources, causing challenges to future black start restoration plans that will need to be studied and resolved. In addition, current black start restoration procedures start from the transmission system and quick-start synchronous generation stations and then work toward restoring the distribution grid. However, with significant DERs, system restoration procedures must be evaluated to account for these DERs, including an investigation into new DER technology like grid-forming inverters used in microgrids.

7.5.4 Future Technology Considerations

As the grid continues to evolve and develop with renewable energy resources, so must the technology used to monitor, control, and transport energy. While technological advancements have been made in some of these areas, much is still to be learned and developed. Such technologies can include, but are not limited to power quality, reactive resources and voltage control, grid monitoring and control capabilities, energy storage requirements, and high-voltage direct current transmission. Future enhancements in power quality will have to be considered because as variable inverter-based generation increases so do the voltage and frequency fluctuations and the harmonics, which can cause a variety of issues on the grid. For reactive resources and voltage control, the Company will have to continue to look at flexible alternative current transmission systems devices, synchronous condensers, and other reactive technologies to help support the electromagnetic fields required to control voltage levels as traditional voltage regulation devices that adjust reactive power like traditional rotating synchronous generators are being replaced with inverter-based generation.

The addition of DERs and the growth and development of EVs and other electrification activities will require future development and enhancements of grid monitoring and control capabilities. Energy storage will become vital to the Company as it moves away from traditional synchronous generation to inverter-based renewable generation due to the intermittence and uncertainty of wind and solar. The Company is already making strides in using energy storage to enhance system reliability as discussed in Section 8.5, ***Battery Storage Pilot Program***. At this time, BESS have negligible impact to the transmission grid. However, as development continues in the years to come, the impact will have to be taken into consideration in reliability studies. Finally, as high-voltage direct current ("HVDC") technology continues to evolve, the Company will have to continue to evaluate the possibility of utilizing HVDC as generation continues to move away from load centers. However, due to the considerably higher cost of HVDC due to the cable and the alternating current / direct current ("AC/DC") converter stations, this technology will have to continue to be evaluated.

The Company intends to rigorously continue to study each of the technologies above and others yet to come to assure that it can deliver safe, reliable, and affordable power to customers.

Chapter 8: Distribution

The Company's obligation to provide safe and reliable service carries on as the Company transitions toward a cleaner energy future. In fact, providing reliable and resilient service becomes inherently more important during this transition when availability of extensive DERs and expanding electrification are added essentials. As the distribution grid evolves to support a more dynamic energy system, the Company must continuously identify new scenarios and solutions to ensure safe and reliable service. Those solutions will likely include emerging technologies, such as a comprehensive distributed energy resource management system and customer-owned assets leveraged for grid support as non-wires alternatives. Regardless of which solutions are implemented, a robust and secure telecommunication infrastructure platform that provides real-time situational awareness and supports analysis and control of grid components will be essential for an adaptable and responsive distribution grid.

This chapter provides an overview of the distribution planning process and an overview of current initiatives related to the distribution grid.

8.1 Distribution Planning

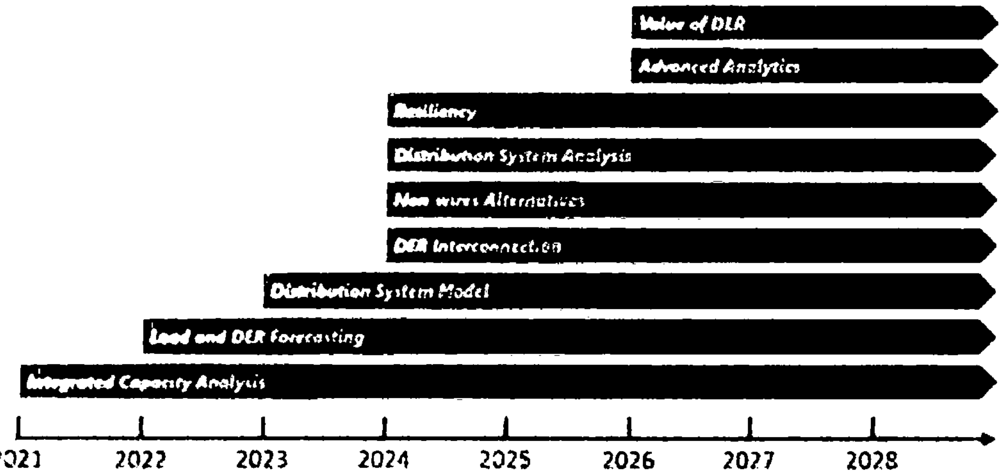
Fundamental changes in the energy industry have driven not only the need to transform the distribution grid, but also to transform how distribution grid planning occurs.

In 2019, the Company presented a white paper that provided a conceptual first look at its transition toward integrated distribution planning ("IDP"). The Company defines integrated distribution planning as a consolidated process to address the capacity, performance, reliability, resilience, and DER integration needs of the distribution grid. The white paper noted that the evolution to IDP requires changes related to people, technologies, and processes. Throughout, trained professionals are vital to leverage the technologies and optimize the processes. Technologies and secure communications that provide real-time visibility into the grid to the customer level are foundational to enable IDP. Processes and tools must then be developed that incorporate the data gathered by the foundational technologies, including advanced distribution modeling and analytical tools that consider a range of possible futures where varying levels of DER and emerging technologies are adopted on the distribution grid. These concepts remain true today.

The Company has made notable successes in the evolution toward IDP since 2019, including successes related to people, such as the centralization of its organizational structure such that one team focuses on all distribution-related modeling and data analysis activities for load and reliability driven investments; technologies, primarily through development and implementation of Grid Transformation Plan investments; and processes, such as the development of an initial forecast of DERs by feeder and publications of hosting capacity maps for different types of DERs.

In 2021, the Company noted its continued work on a roadmap for IDP that adds tangible goals and timeframes to IDP maturity and stated its intention to present that roadmap in 2023. The Company's current IDP roadmap is attached as Appendix 8A to this document (the "2023 IDP Roadmap" or the "Roadmap"). The Roadmap presents tangible goals for the components of IDP on which the Company plans to focus in the near term. Figure 8.1.1 provides a visual representation of the Roadmap.

Figure 8.1.1: 2023 IDP Roadmap



The IDP concept is not static, and further changes are expected in the next decade. But the 2023 IDP Roadmap sets the Company on a trajectory to give higher priority to foundational components of IDP, such as advanced forecasting and system model enhancements, while balancing the resources required to implement these components and the interdependencies among many of the components.

8.2 Existing Distribution Facilities

The Company's existing distribution grid in Virginia consists of more than 54,000 miles of overhead and underground cable, and over 400 substations operating at distribution voltage levels ranging from 4 kV to 46 kV. The distribution grid utilizes a variety of devices for functions, from voltage control to power flow management, and relies on multiple operating systems for various functions, from customer billing to outage management.

Appendix B of the executive summary of the Grid Transformation Plan filed in Case No. PUR-2023-00051 provided a detailed description of the Company's existing distribution grid.

8.3 Grid Transformation Plan

The Grid Transformation Plan is the Company's comprehensive plan to transform its electric distribution grid to facilitate the integration of DERs, to enhance grid reliability and security, and to improve the customer experience.

In Phases I and II of the Grid Transformation Plan, which generally covers investments in grid transformation projects between 2019 and 2023, the Company pursued projects that are foundational to the vital objectives of grid transformation. From these initial investments the Company has seen notable successes that have a direct and positive effect on its customers. The Company has deployed AMI to nearly three-quarters of its customers in Virginia, enabling these customers to take control of their energy usage with the granular data that smart meters provide. The Company's new customer information platform ("CIP") went live in April 2023, enabling the systems needed to modernize the customer relationship. The Company has enhanced grid reliability through multiple grid transformation projects, providing a direct benefit to customers and improving the availability of the grid for DERs. And the Company has facilitated the integration of DERs, for example, through the launch of two hosting capacity tools that provide guidance to customers and developers about siting clean energy installations and through its rebate program for the installation of smart charging infrastructure for EVs.

In Phase III, which is currently pending before the SCC in Case No. PUR-2023-00051, the Company seeks to continue its work on approved projects toward the objectives of grid transformation based on the same need that has been shown in prior proceedings. Specifically, the Company seeks to complete the deployment of two foundational GT Plan investments—AMI and the CIP. The Company also seeks to continue its three grid infrastructure projects approved by the SCC in prior phases—mainfeeder hardening, targeted corridor improvement, and voltage island mitigation—along with three of its previously approved grid technologies projects—a DER management system, voltage optimization enablement, and substation technology deployment. Together, these investments will continue to enhance grid reliability and to facilitate the integration of DERs. Finally, the Company seeks to continue investing in enhanced telecommunications and physical substation security, as well as investments in cyber security and customer education as needed to support other proposed projects. Phase III also requests approval of two new projects. First, the Company proposes to deploy a new outage management system to replace an outdated operating system that cannot accommodate the complexity that a modern distribution grid requires. Second, the Company seeks approval of a process to evaluate energy storage systems as non-wires alternatives to traditional distribution investments. This process will enable the Company to gain experience with this integrated distribution planning concept in a manner that will provide useful information as the Company moves forward with non-wires alternatives and that may result in the integration of energy storage systems that can dynamically respond to changing grid conditions.

Overall, the Grid Transformation Plan represents the optimal package to facilitate the integration of DERs while maintaining and enhancing reliable and secure electric service. Achieving these objections is vital to the clean energy goals discussed in this 2023 Plan.

8.4 Strategic Undergrounding Program

The Company is continuing the SUP, which is in its seventh year. Originally conceived as a 4,000-mile program in 2014, the Company has converted approximately 1,888 miles of outage-prone overhead tap lines as of December 31, 2022. A legislative sunset clause currently requires the SUP to conclude in 2028. More details on the SUP are available in the Company's annual filings with the SCC, which specify the miles of tap lines converted and their locations, tap line reliability performance pre- and post-conversion, and system-wide reliability statistics.

Both local and system-wide benefits are key aspects of the SUP. Specifically, the SUP was designed to shorten restoration times in severe weather events by reducing the number of labor-intensive work locations associated with outage-prone single-phase overhead tap lines, especially those behind homes with significant tree coverage. By converting those tap lines to underground, directly served customers will either see a shorter outage or no outage. Perhaps more importantly, this enables crew redeployment to other outage locations, allowing a faster recovery after severe weather events for the benefit of all customers. The SUP remains the most effective and comprehensive solution for eliminating work associated with systemic tap line outages and is complemented by the mainfeeder hardening program in the Grid Transformation Plan, which targets mainfeeders serving customers with the poorest reliability.

8.5 Battery Storage Pilot Program

Specific to the distribution grid, the Company is currently studying the use of battery energy storage systems on its distribution grid through the pilot program established by the GTSA. Two BESS came online on the distribution grid in 2022:

- BESS-1, a 2 MW/4 MWh AC lithium-ion BESS, that is studying the prevention of solar backfeeding onto the transmission grid at a substation located in New Kent County; and
- BESS-2, a 2 MW/4 MWh AC lithium-ion BESS, that is studying batteries as a non-wires alternative to reduce transformer loading at a substation located in Hanover County.

The Company also deployed a lithium-ion BESS at its Scott Solar Facility to study solar plus storage.

The Company filed its first annual report on the pilot program with the SCC on March 31, 2023, in Case No. PUR-2019-00124, including lessons learned from constructing these pilot BESS. As to the two distribution BESS, throughout 2022, BESS-1 showed excellent progress towards meeting its objectives, with initial data analysis indicating that both transformer load tap changer operations and total backfeed have been reduced. Initial results are also very promising for BESS-2, with 18% percent of the exported energy occurring during the two highest load hours of each day on the associated transformer and 39% occurring during the four highest load hours of each day.

These BESS provide the Company the opportunity to study important statutory objectives, and the information and experience gained from each will provide valuable insight and experience toward deployment of BESS in the future. The Company continues to explore additional unique energy storage use cases for future consideration within the battery storage pilot program.

8.6 Electric School Bus Program

The Company's Electric School Bus Program combines the Company's efforts with energy storage technologies and electric vehicles, while at the same time assisting customers' decarbonization efforts. In addition to reducing the carbon footprint of the Commonwealth and improving air quality for students, the batteries in electric school buses can be used to increase the stability and reliability of the grid and can help to facilitate the integration of renewable energy resources such as solar and wind onto the distribution grid. In Phase I of this Program, the Company supported 15 localities and 50 electric school buses. The Company is also supporting localities that receive Virginia Department of Environmental Quality Clean School Bus grants, American Recovery Act Electric School Bus rebates, and EPA Clean School Bus rebates.

The Electric School Bus Program, coupled with a modernized grid, will allow the Company to gain understanding and knowledge regarding strategic deployment of EVs as resources for the benefit of customers and the grid.

8.7 Rural Broadband Program

Originally a pilot program, the rural broadband program is now a permanent, innovative approach to install middle-mile fiber to help achieve universal broadband access across the Commonwealth.

The Company is leveraging the telecommunications infrastructure deployed as part of the Grid Transformation Plan by using a portion of the fiber capacity to meet its own distribution grid needs and then leasing another portion to an internet service provider. By utilizing the telecommunication infrastructure for both operational needs and broadband access, the Company can reduce broadband deployment costs for internet service providers, enabling these providers to deliver high-speed internet access to unserved residences and business.

The Company currently has agreements with over 30 counties to reach unserved areas through partnerships with five internet service providers, including All Points Broadband, RURALBAND, EMPOWER Broadband, Firefly Fiber Broadband, and BARC Connects. The middle-mile project in Surry County is complete and RURALBAND is actively serving Surry County residents. Projects are underway (either in development or under construction) in Botetourt, Stafford, Westmoreland, Richmond, Northumberland, King George, Lancaster, King William, Louisa, Appomattox, Augusta, Loudoun, Culpeper, Fauquier, Rockingham, Hanover, Middlesex, Sussex, Dinwiddie, Albemarle, Buckingham, Cumberland, Fluvanna, Goochland, Nelson, Powhatan, Brunswick, Halifax, and Mecklenburg counties.

As of March 31, 2023, approximately 271 miles of fiber have been installed as part of the Rural Broadband Program, with approximately 2,500 additional miles planned in the remainder of 2023 and beyond.

Chapter 9: Other Information

This chapter provides other information in response to specific SCC or NCUC requirements.

9.1 Environmental Justice

The Virginia Environmental Justice Act ("VEJA") sets the policy of Virginia to promote environmental justice, ensuring the fair treatment and meaningful involvement of every person—regardless of race, color, national origin, income, faith, or disability—regarding the development, implementation, or enforcement of any environmental law, regulation, or policy. North Carolina's Executive Order No. 246 directs agencies to elevate the consideration of environmental justice, including by identifying an agency point person for environmental justice efforts and by developing a public participation plan to ensure the public is meaningfully engaged in government decision-making.

The transition to a clean energy future requires substantial development of new infrastructure, which has the potential to affect surrounding communities. Recently published draft environmental justice guidance from the Virginia Department of Environmental Quality concluded that applying VEJA definitions results in 53% of the total geographic area and 59% of the population of Virginia meeting the definition of an environmental justice community. The draft guidance also outlined a process by which new projects must be evaluated for environmental justice considerations. The Company looks forward to engaging in the guidance development process as it is finalized.

Dominion Energy and the Company are committed to ensuring that all communities have a meaningful voice in planning and development processes. In cases where a community meets the definition of an environmental justice community, the Company's approach to environmental justice requires consideration of proactive community engagement strategies to ensure that all people have an opportunity to participate meaningfully in the decision-making process. This means providing information in an accessible way, providing opportunities for community members to voice their concerns and provide input, and that such concerns and input are appropriately responded to and that the Company works to minimize or mitigate any disproportionate impacts.

The Company believes that consistent with the mandates and goals of the VCEA and North Carolina Executive Order No. 246, as well as federally developed environmental justice policy, environmental justice is best evaluated and carried out on a case-by-case basis, informed by the location of the project in question and project-specific characteristics. The Company has established an environmental justice review process for evaluating its specific projects and programs that implicate environmental justice consistent with relevant laws and regulations, as well as previously developed EPA guidance, and currently accepted best practices. Based on this, the Company presents the results of these project-specific review processes in the relevant proceedings before the SCC, such as in its applications to construct new generating facilities or new transmission lines and will do so as appropriate in relevant proceedings before the NCUC.

9.2 Customer Education

The Company is committed to improving the customer experience. Key to achieving this goal is educating customers about their energy consumption and how to manage their costs, and empowering customers to take advantage of the numerous enhanced customer capabilities enabled by the Grid Transformation Plan and other initiatives.

The Company's customer education initiatives include providing demand and energy usage information, educational opportunities, and online customer support options to assist customers in managing their energy consumption and taking advantage of new incentives and offerings. The educational initiatives discussed below apply to the Company's customers in both Virginia and North Carolina.

Website and Supporting Print Collateral

The Dominion Energy website—https://www.dominionenergy.com—is a main hub for public education. The Company offers program- and project-specific information, factsheets, brochures, videos, and other supporting documents to provide background and updates on the benefits and enhanced capabilities associated with a variety of investments and initiatives. These include, but are not limited to, approved elements of the Grid Transformation Plan, major infrastructure projects, and new offerings such as rates, tools, and mobile apps as they become available.

Social Media

The Company uses the social media channels of Twitter® and Facebook® to provide real-time updates on energy-related topics, promote Company messages, and provide two-way communication with customers. The Company also manages pages on YouTube® and Instagram for further outreach to the general public, residential customers, and business customers. LinkedIn is leveraged for reaching commercial and industrial customers.

The Company's Twitter® account is available online at: https://twitter.com/dominionenergy.
The Company's Facebook® account is available online at:
https://www.facebook.com/dominionenergy.
The Company's YouTube® account is available online at
https://www.youtube.com/user/DomCorpComm.
The Company's Instagram account is available online at
https://www.instagram.com/dominionenergy/.
The Company's LinkedIn account is available online at
https://www.linkedin.com/company/dominionenergy/.

News Releases

The Company prepares news releases and reports on the latest developments regarding its customer-facing initiatives and provides updates on Company offerings and recommendations for saving energy as new information and programs become available. Current and archived news releases can be viewed at: https://news.dominionenergy.com/news.

Customer Information Platform

The customer information platform—approved by the SCC as part of the Grid Transformation Plan—will enable the Company to provide customers with better information. For example, customers will be able to utilize various notification, billing, and pay options to more easily monitor usage and to take advantage of new rate structures and rate comparison tools. The implementation of the customer information system and customer portals, both of which were components of the customer information platform, were completed in April 2023. Overall, with the new capabilities and customer functionality within the customer information platform, customers will be in a better position to save time and money.

Energy Conservation Programs
The Company's website has a section dedicated to energy conservation that contains helpful information for both residential and non-residential customers, including information about the Company's DSM programs. Dozens of programs are featured on the website and include eligibility guidelines, program details, steps to enroll, and success stories, as well as contact information to speak with program specialists. Through consumer education using a variety of channels to reach multiple customer classes, the Company is working to encourage the adoption of energy-efficient technologies in residences and businesses in Virginia and North Carolina.

Online Energy Calculators
The Company is committed to helping customers save on their energy bills and provides saving tips and a "Lower My Bill Guide" on the Company website. Home and business energy calculators are provided as well to estimate electrical usage for homes and business facilities. The calculators can help customers understand specific energy use by location and discover new means to reduce usage and save money. For customers considering the environmental impact of transportation choices, a calculator is offered to compare emissions and cost savings of cars side-by-side with more efficient hybrid or all-electric vehicles. An appliance energy usage calculator and holiday lighting calculator are also available to customers. The energy calculators are available at: https://www.dominionenergy.com/home-and-small-business/ways-to-save/energy-saving-calculators.

Community Outreach – Trade Shows, Exhibits, and Speaking Engagements
The Company conducts outreach seminars and speaking engagements in order to share relevant energy conservation program information to both residential and commercial audiences. The Company also participates in various trade shows and exhibits at energy-related events to educate customers on the Company's programs and inform customers and communities about the importance of implementing energy-saving measures in homes and businesses and taking advantage of new rates and offerings as they become available. Company representatives positively impact the communities the Company serves through presentations to elementary, middle, and high school students about its programs, wise energy use, and environmental stewardship. Additional partnerships with the educational community are offered through mentoring initiatives, philanthropic support, and other means to strengthen science, technology, engineering, and mathematics competitiveness in an effort help prepare students for tomorrow's workplace. Information on educational grants, scholarships, and programs for teachers and students is available on the Company's website at: https://www.dominionenergy.com/our-company/customers-and-community/educational-programs.

For example, Project Plant It! is an educational community learning program available to students in the service areas where the Company conducts business. The program teaches students about the importance of trees and how to protect the environment through a variety of hands-on teaching tools such as a website with downloadable lesson plans for use at home and in classrooms, instructional videos, and interactive games. To enhance the learning experience, Project Plant It! provides each enrolled student with a redbud tree seedling to plant at home or at school. Since 2007, more than 600,000 tree seedlings will have been distributed to children in states where the Company operates. According to the Virginia Department of Forestry, this equates to about 1,500 acres of new forest if all the seedlings are planted and grow to maturity. In 2021, Project Plant It! added a new bee pollinator program, providing wildflower seed packets to teach students about the essential role of bees and other pollinators to the sustainability of the environment. Visit website for more information, https://projectplantit.com/.

9.3 Accelerated Renewable Energy Buyers

In Virginia, the law permits certain customers who certify as ARBs to be exempt from certain costs and benefits related to the mandatory RPS Program. The law defines an ARB as a commercial or industrial customer, irrespective of generation supplier, with an aggregate load over 25 MW in the prior calendar year, that enters arrangements to (i) obtain RECs from RPS eligible sources ("REC-only ARBs") or (ii) bundled capacity, energy, and RECs from solar or wind generation within the PJM region ("Bundled ARBs"). ARBs must be a non-residential customer. Examples of types of customers that qualify as an ARB could be a single industrial facility, a single data center site, a group of commercial office building accounts under the same common parent, or a group of accounts of a retail business under the same common parent. ARBs must certify annually through the processes established by the SCC. Customers that meet the definition of an ARB are not required to certify as ARBs nor are they required to certify up to the full volume of their load—it is the choice and responsibility of the specific customer.

From a ratemaking perspective, customers who certify as ARBs are exempt from paying certain costs, and the remaining costs are allocated to other Company customers. The Company incorporated this aspect of ARBs into the Company Methodology for the Virginia consolidated bill analysis discussed in Section 2.5, ***Virginia Consolidated Bill Analysis***, by removing the actual usage and projected usage from the applicable customer classes for each account that was submitted for certification as an ARB in 2023 according to their submitted exemption status (*i.e.*, full or partial) for the purposes of Virginia RPS Program compliance.

From a planning perspective, ARBs are factored into the Company's planning processes in two ways.

First, all certified ARBs reduce the Company's obligation under the Virginia RPS Program. To the extent a customer certifies as an ARB, that customer's load would be deducted from the Company's RPS Program compliance obligation in proportion to the customer's ARB-certified load. For purposes of this 2023 Plan, the Company used the 2022 production for (i) all Company facilities that are under contract with a customer seeking certification as an ARB in the 2023 certification process, and (ii) all facilities that were submitted by the customer seeking certification as an ARB in the 2023 certification process to calculate the percentage of each customer's load covered by its renewable energy facilities The Company then maintained the calculated percentage to project that customer's load over the 25-year Study Period of this 2023 Plan, which assumes customer growth and that each facility maintains its 2022 production during the life of the contract. For example, if a customer currently is able to certify as an ARB and demonstrated they were able to meet 100% of their 2022 load through qualified renewable energy, the 2023 Plan assumes this customer would continue to meet 100% of their load in the future. The Company repeated this process for each customer seeking certification as ARB.

Second, the capacity of solar or wind resources that Bundled ARBs have under contract offset the development targets for solar and onshore wind established through the VCEA. For purposes of this 2023 Plan, the Company has offset its development targets based on information submitted for the ARB certification process in 2023. The Company updates these offsets annually based on information provided by ARBs during the annual ARB certification process.

Importantly, a customer's status as an ARB does not affect the Company's obligation to meet the electricity supply service needs (*i.e.*, capacity, energy, and ancillary services) of the customer, assuming the customer receives these services from the Company rather than from a competitive service provider. In other words, the Company's load forecast and planning obligations do not change if a portion of forecasted non-residential load increases come from customers who may certify as ARBs. These customers must be provided electric supply service regardless. Accordingly, the Company did not adjust its load forecasts to account for ARBs, except when the forecast was used to estimate the Company's annual compliance obligations under the Virginia RPS Program. That said, the Company has provided sensitivities on Alternative Plan B under different load forecasts to show the effect if the load forecast were to vary for any number of reasons; see Section 2.6, ***Sensitivity Analyses***.

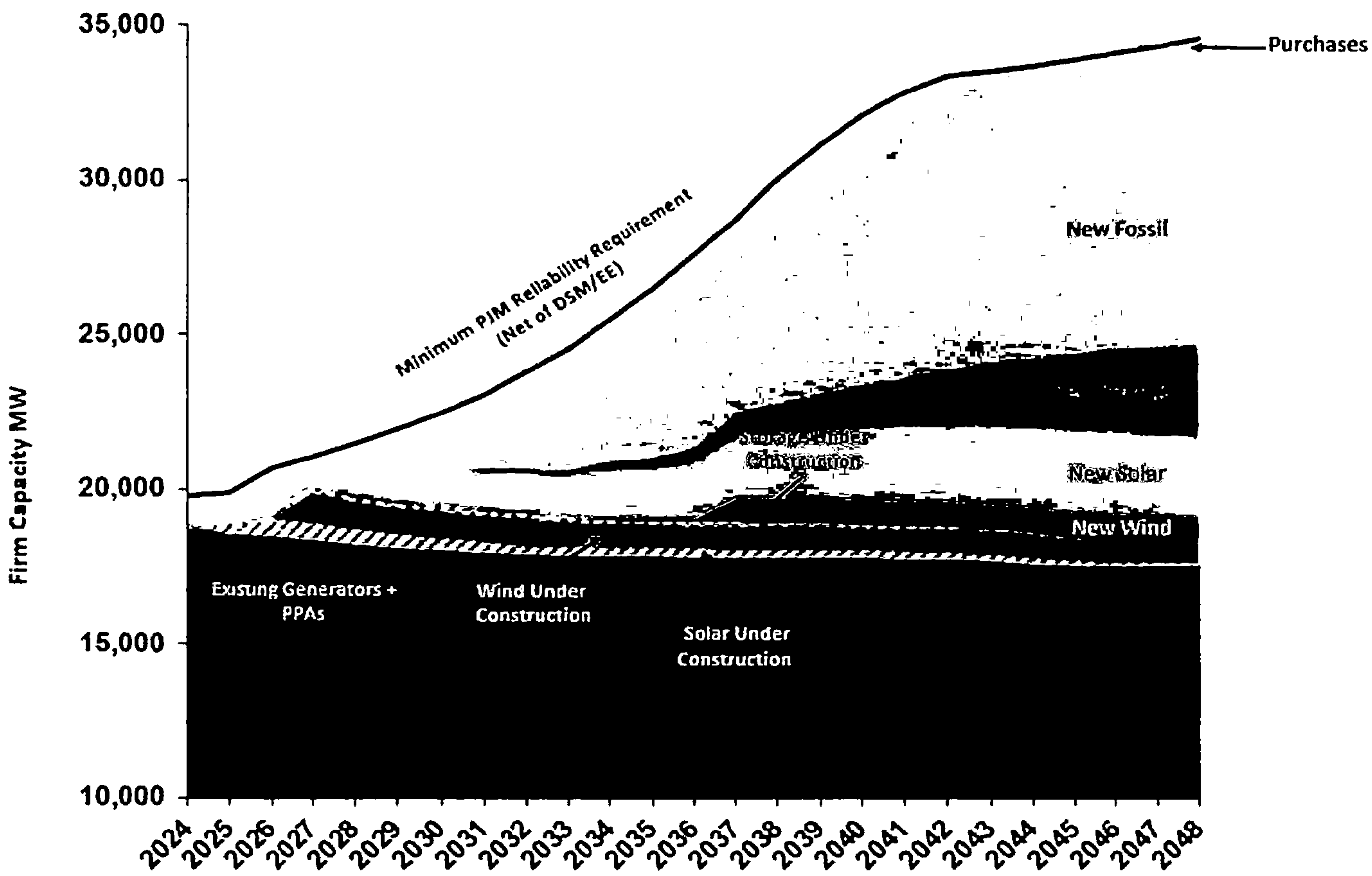
9.4 Economic Development Rates

As of March 2023, the Company has 10 customer locations in Virginia receiving service under economic development rates. The total load associated with these rates is approximately 226 MW. As of March 2023, the Company has one customer in North Carolina receiving service under an economic development rate. The total load associated with this rate is approximately 2 MW.

APPENDICES

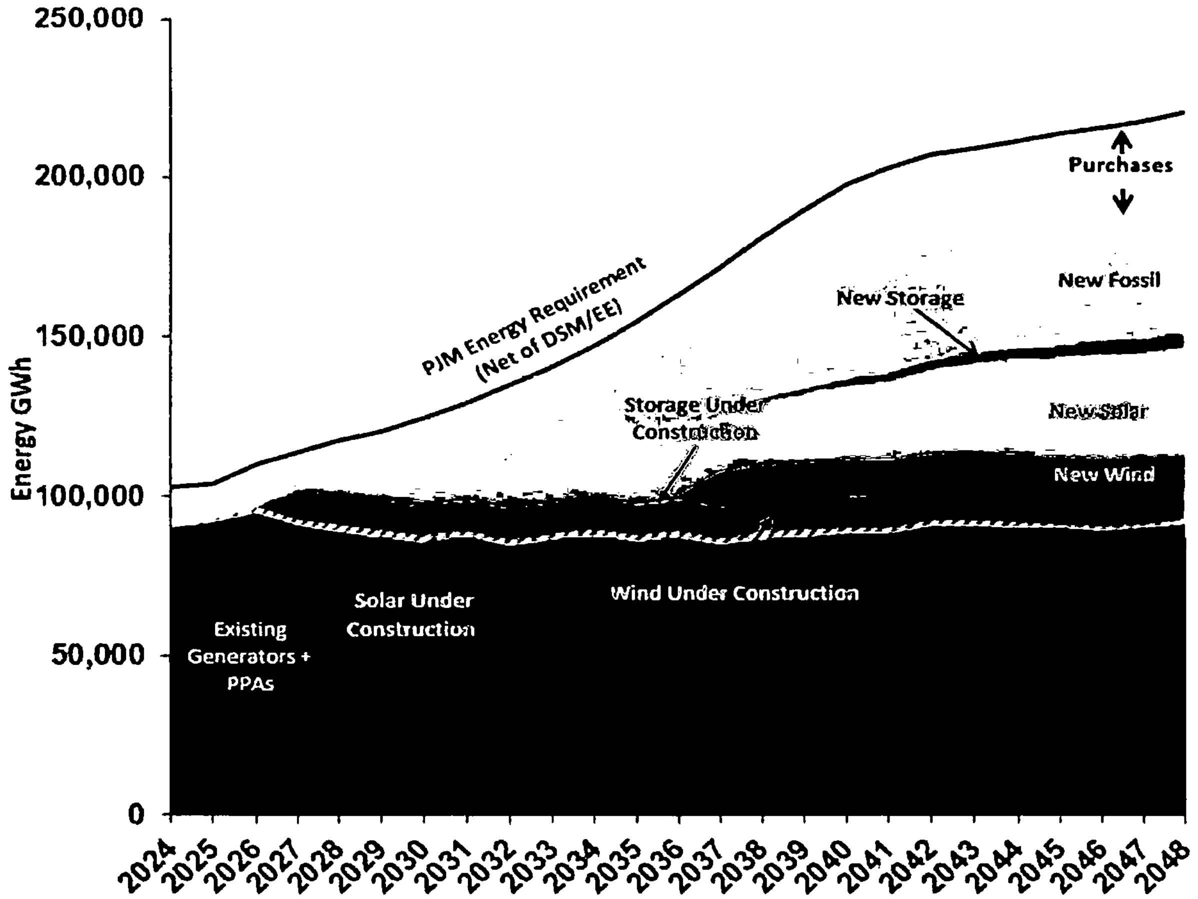
Appendix 2A: Plan A -Summer Capacity, Energy, and RECs

Capacity



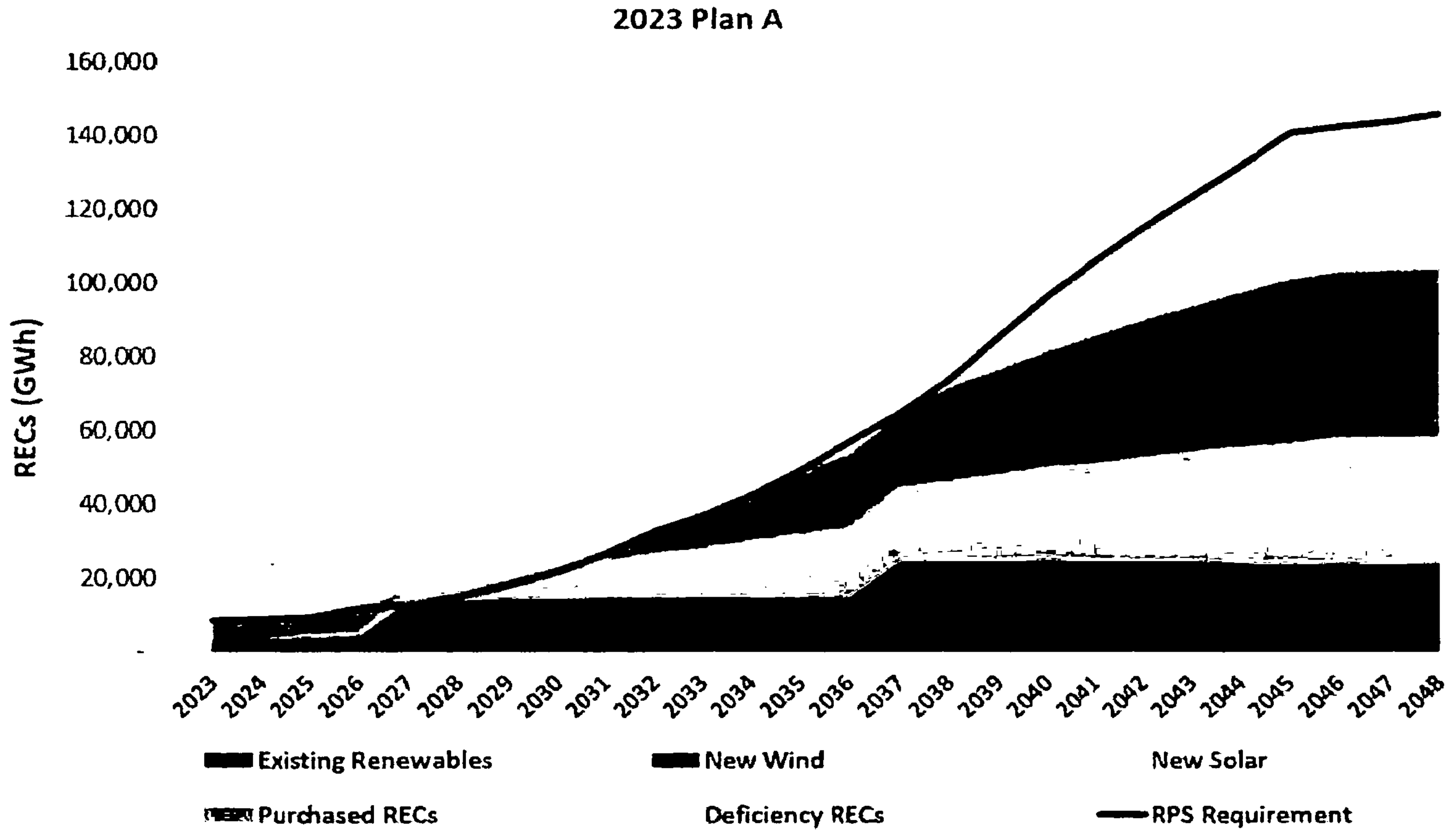
Appendix 2A: Plan A -Summer Capacity, Energy, and RECs

Energy



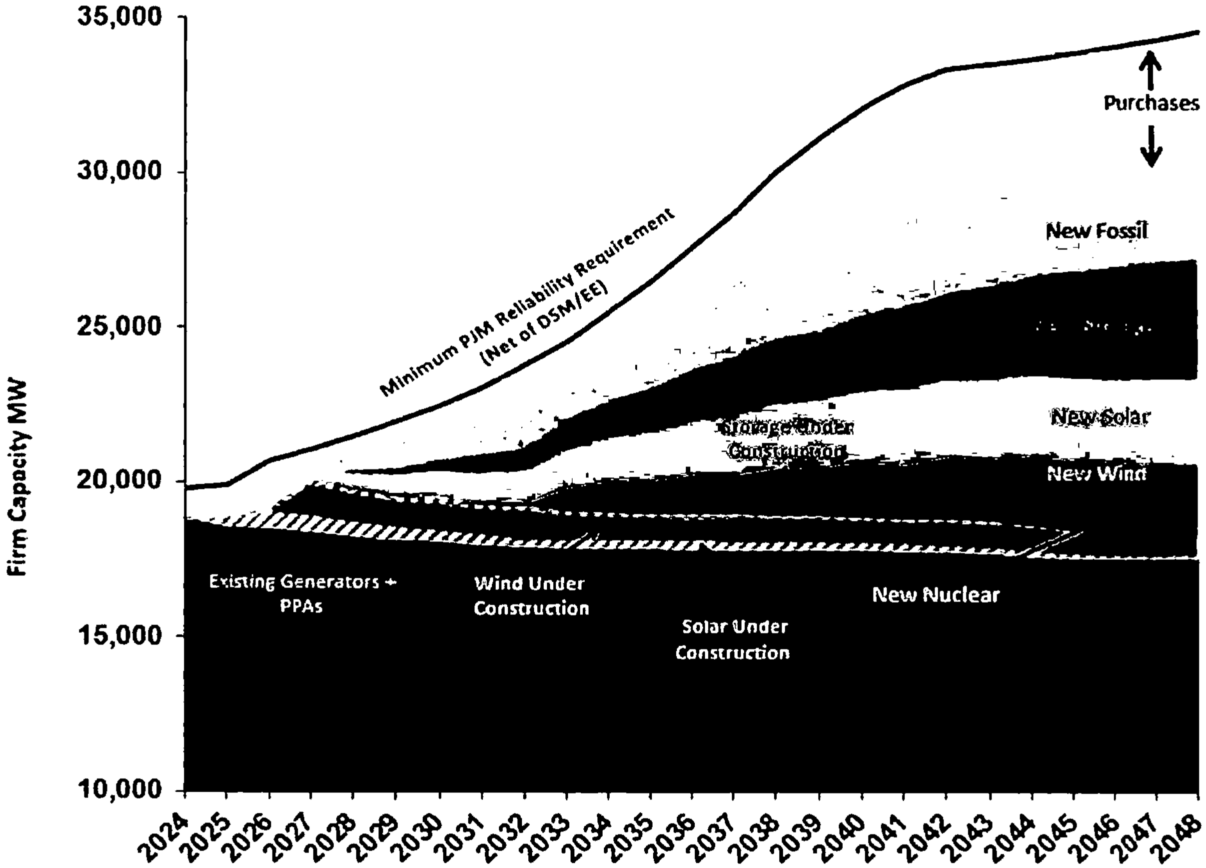
Appendix 2A: Plan A -Summer Capacity, Energy, and RECs

RECs



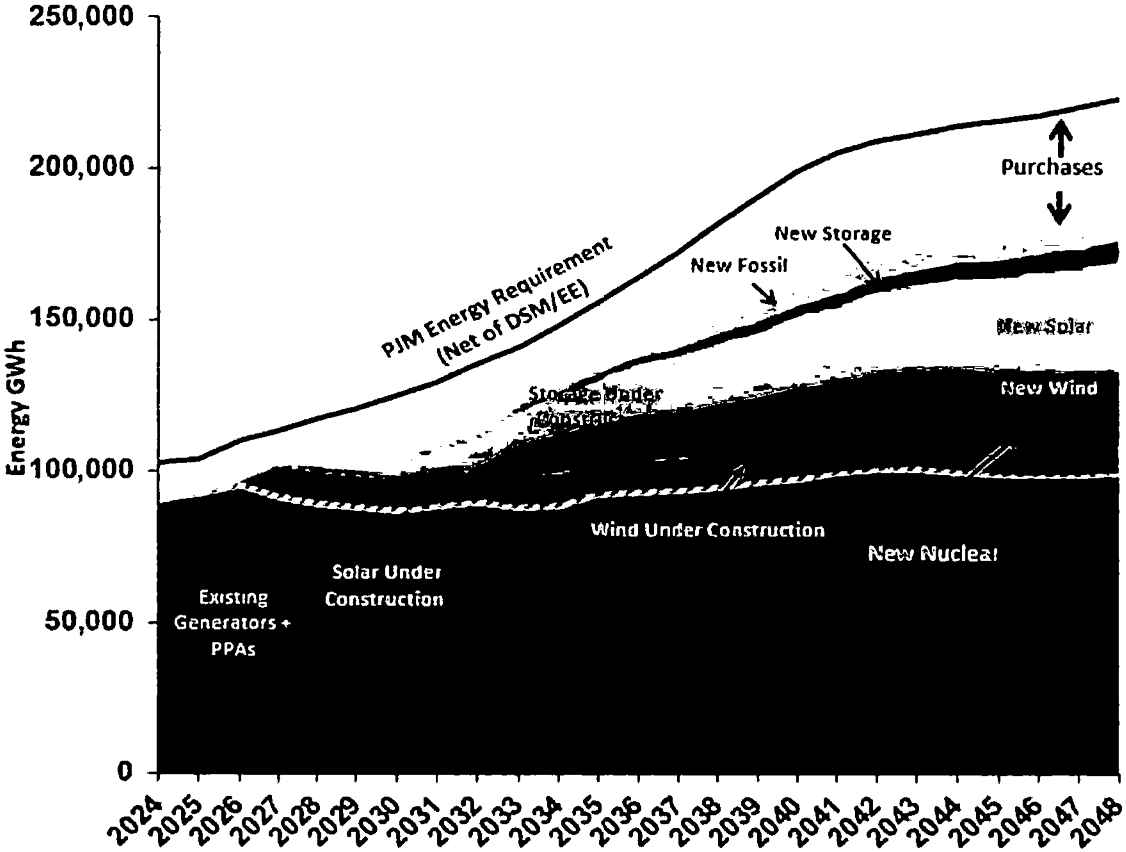
Appendix 2A: Plan B - Summer Capacity, Energy, and RECs

Capacity



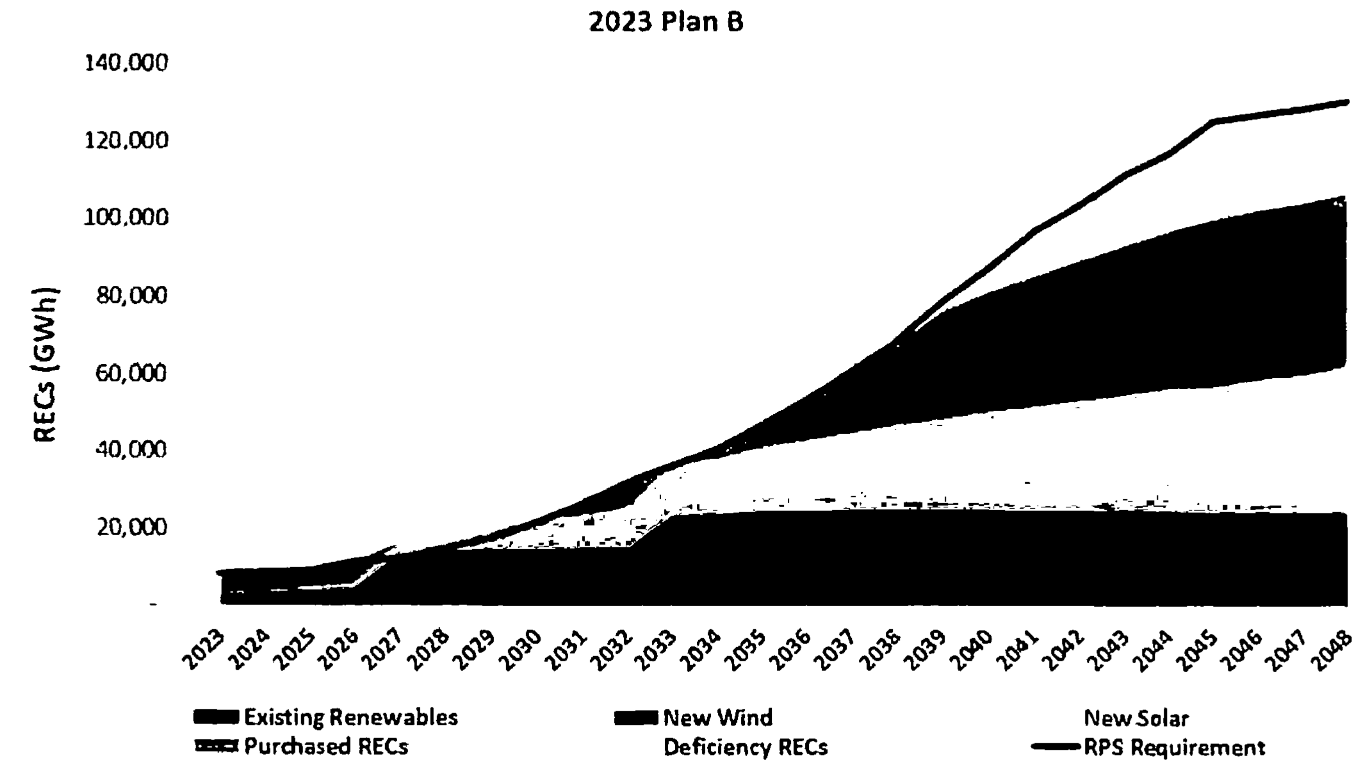
Appendix 2A: Plan B - Summer Capacity, Energy, and RECs

Energy



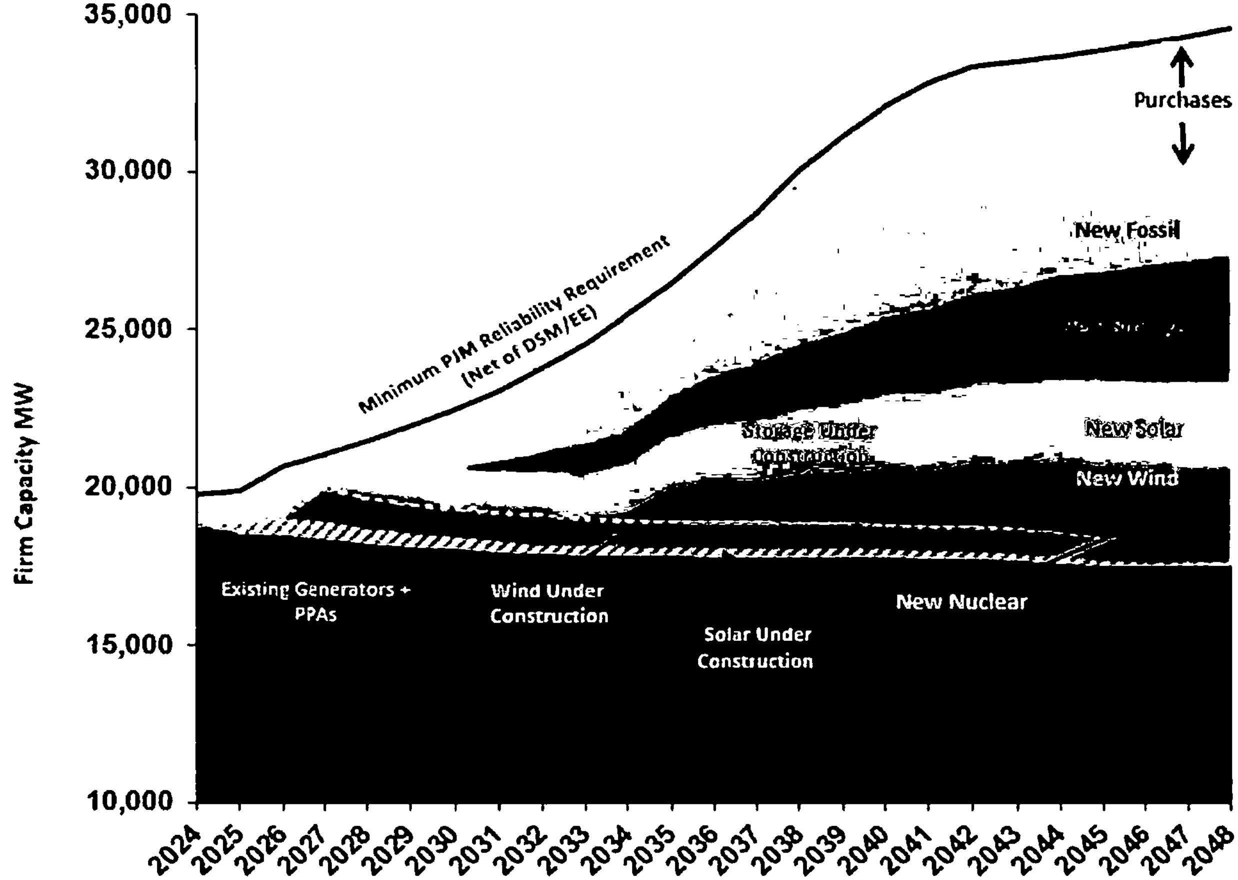
Appendix 2A: Plan B - Summer Capacity, Energy, and RECs

RECs



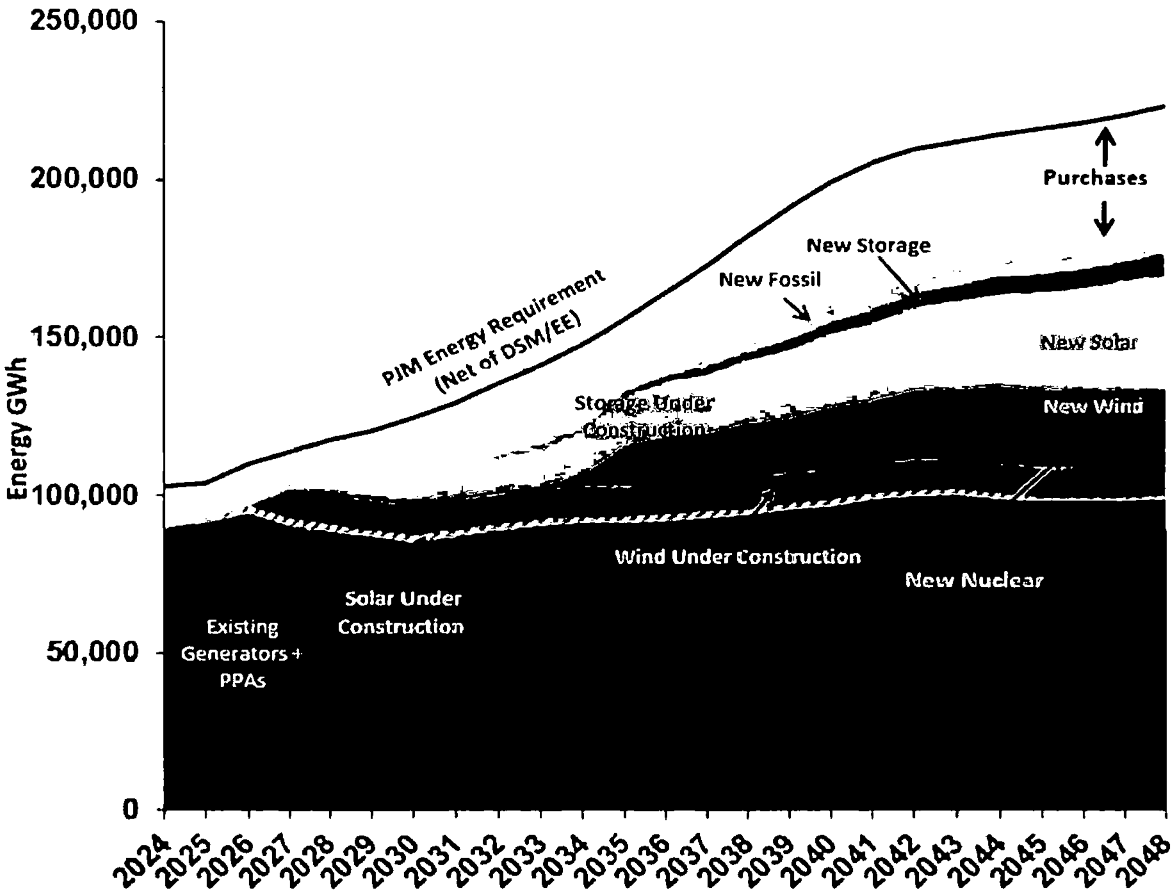
Appendix 2A: Plan C - Summer Capacity, Energy, and RECs

Capacity



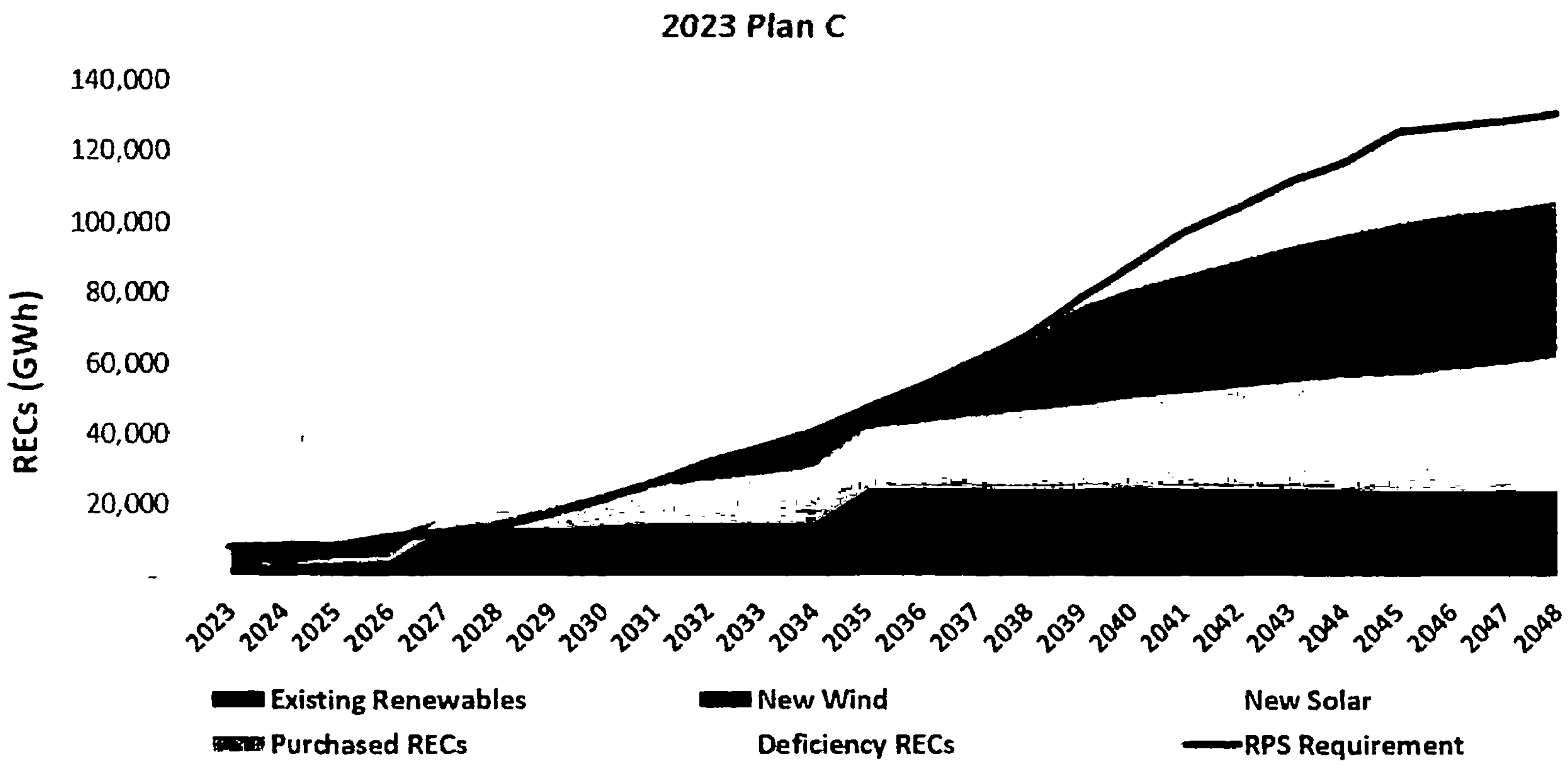
Appendix 2A: Plan C - Summer Capacity, Energy, and RECs

Energy



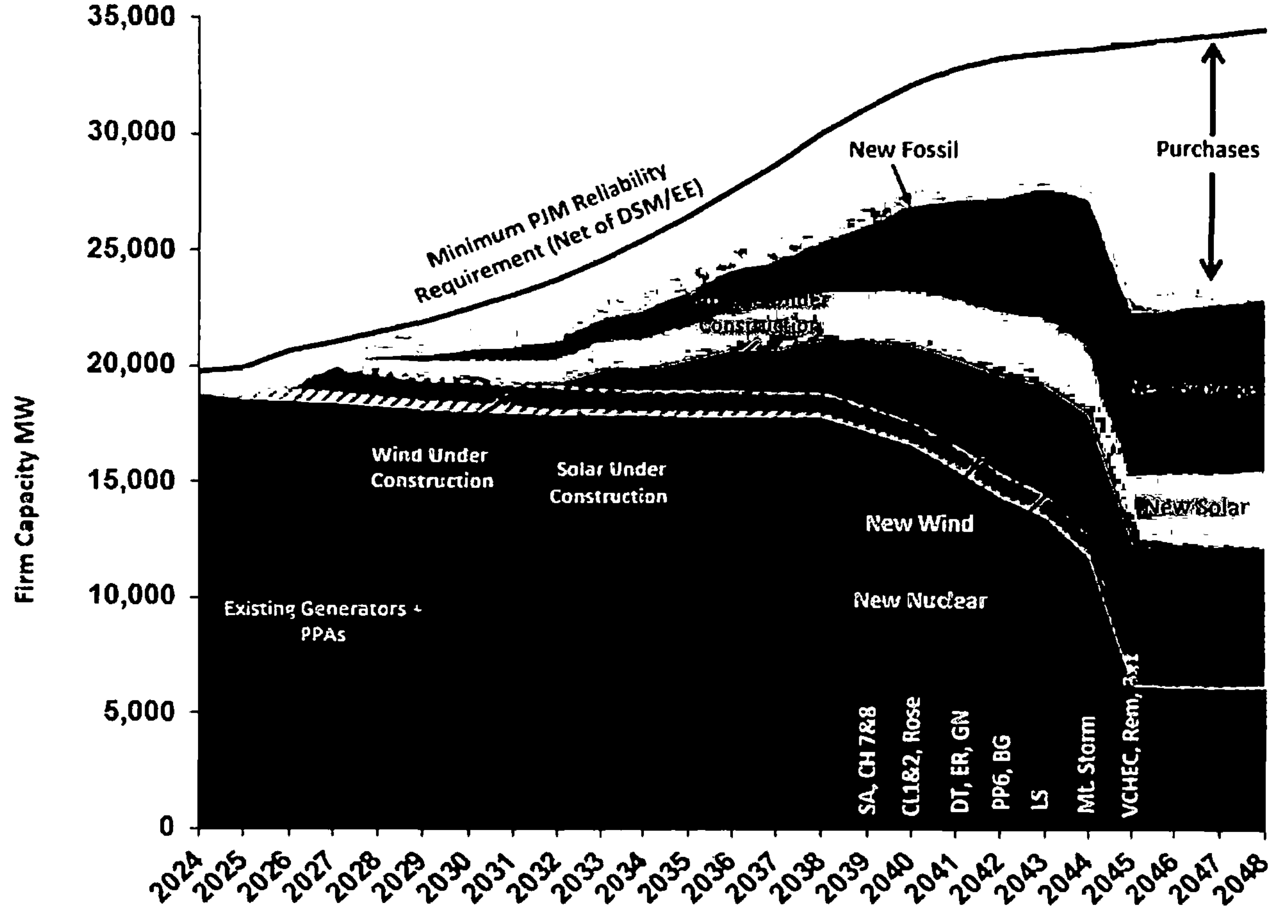
Appendix 2A: Plan C - Summer Capacity, Energy, and RECs

RECs



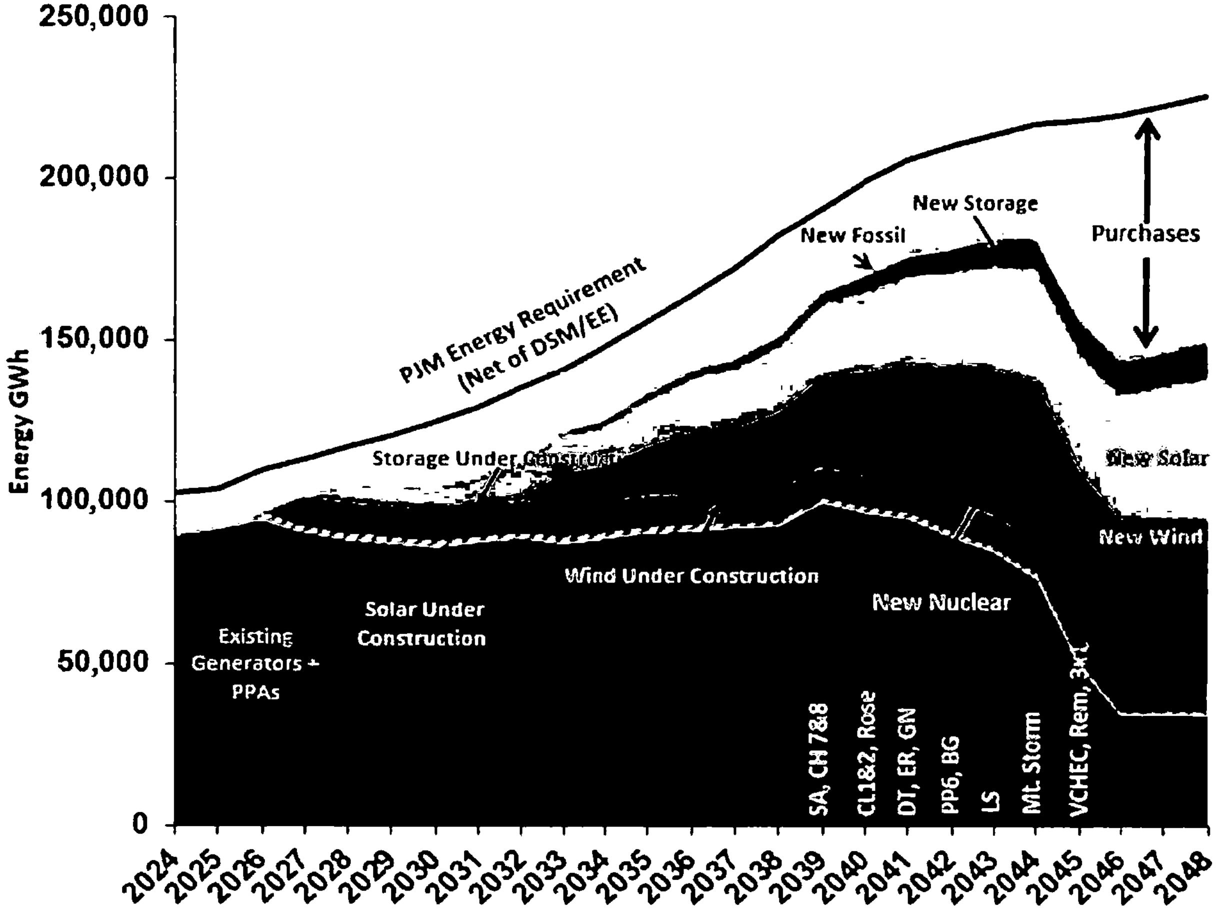
Appendix 2A: Plan D - Summer Capacity, Energy, and RECs

Capacity



Appendix 2A: Plan D - Summer Capacity, Energy, and RECs

Energy



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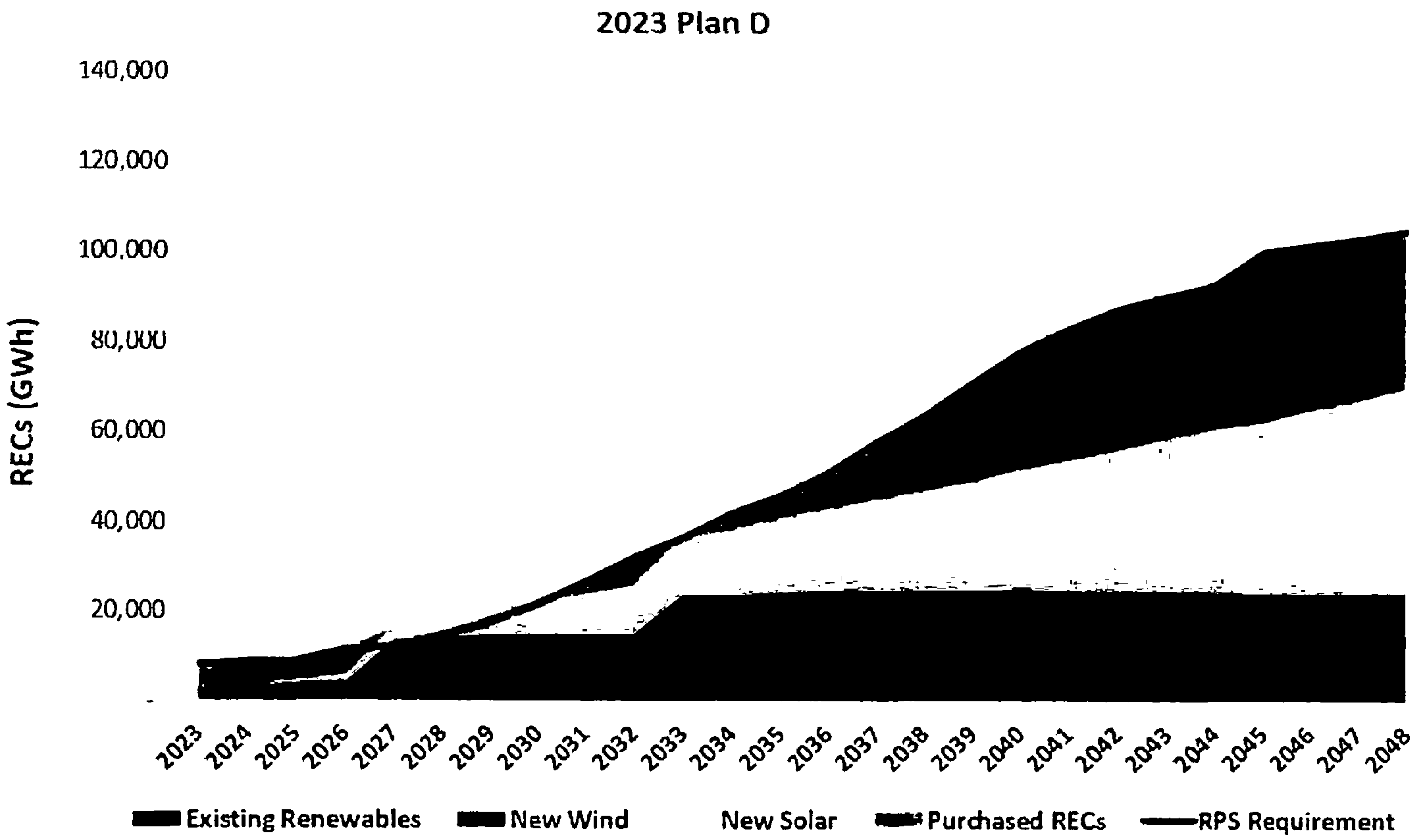
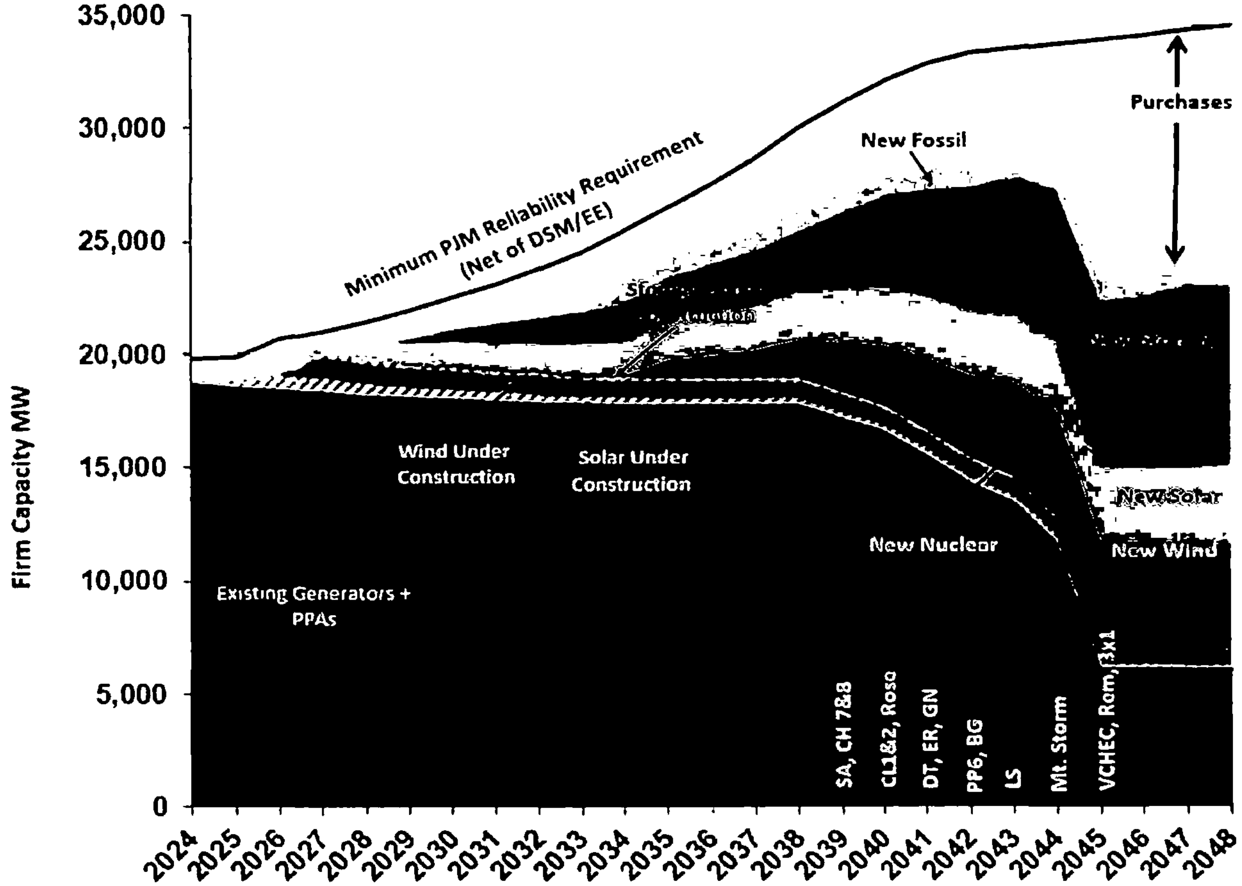
Appendix 2A: Plan D - Summer Capacity, Energy, and RECs

RECs



Appendix 2A: Plan E - Summer Capacity, Energy, and RECs

Capacity



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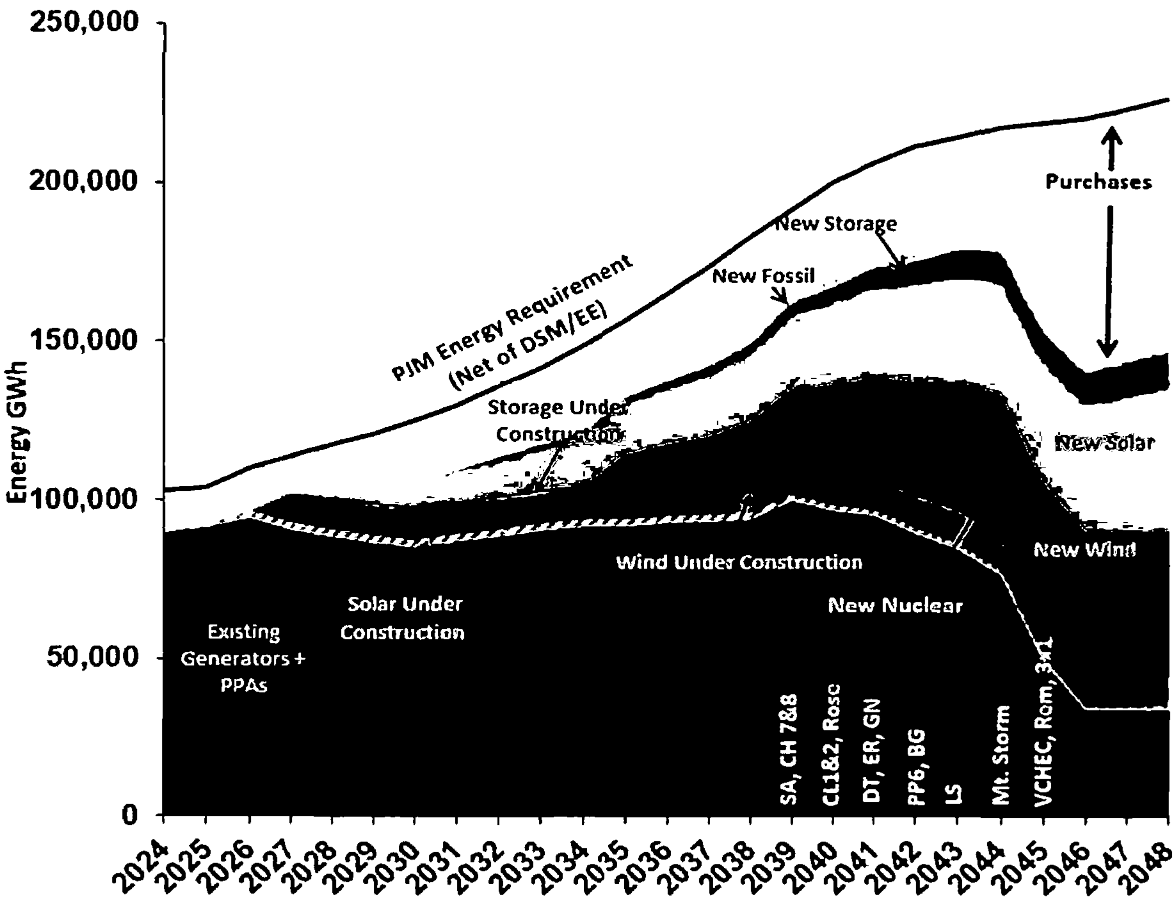
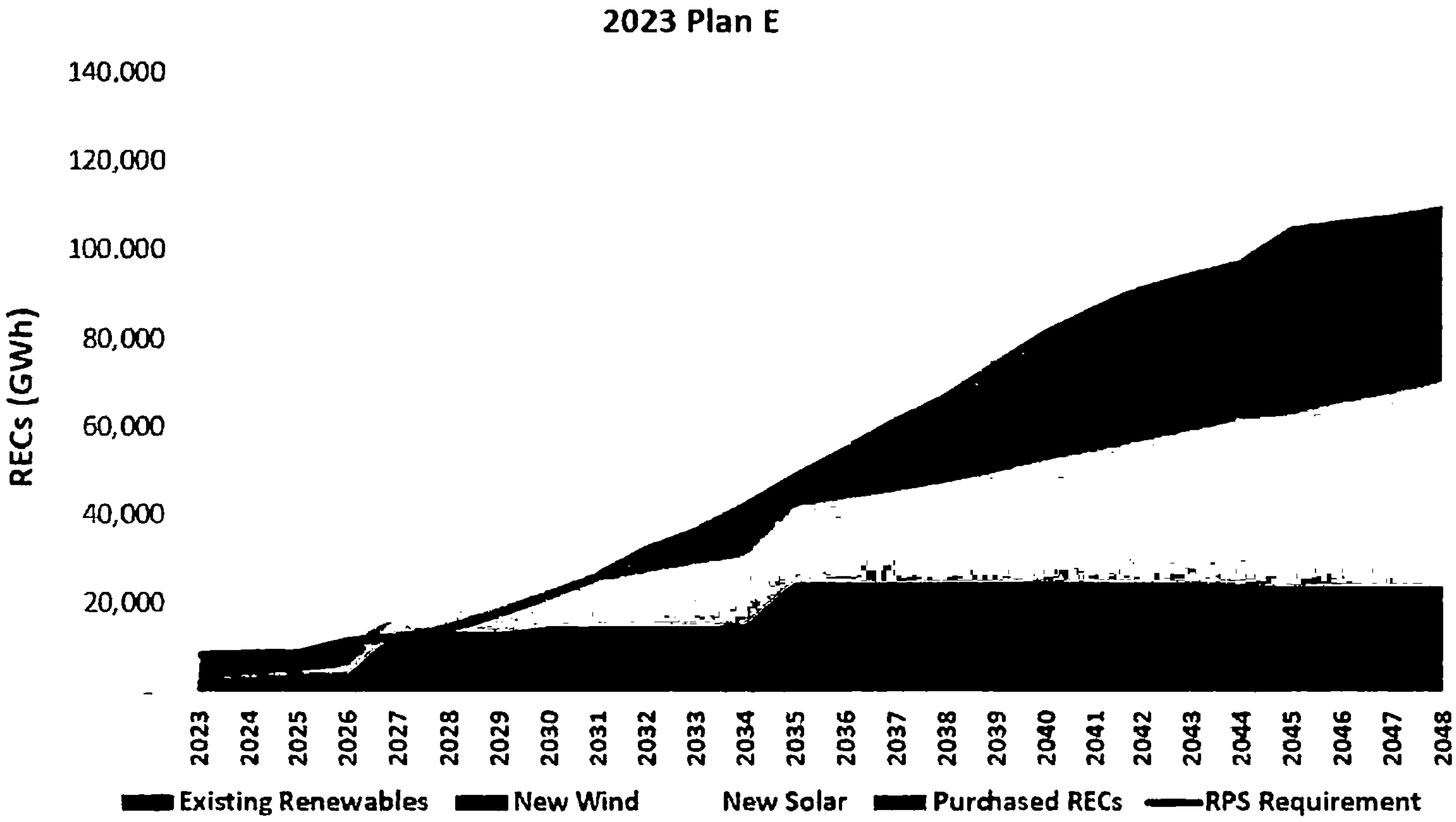
Appendix 2A: Plan E - Summer Capacity, Energy, and RECs

Energy



Appendix 2A: Plan E - Summer Capacity, Energy, and RECs

RECs



Appendix 2B (i-iii): Capacity Information Directed by the SCC

	2023 PJM Load Forecast			
	Coincident Peak (CP)		Non-Coincident Peak (NCP)	
Year	DOM Zone Summer Forecast	LSE Equivalent	DOM Zone Summer Forecast	LSE Equivalent
2023	21,274	16,998	21,920	17,552
2024	22,126	17,266	22,828	17,867
2025	23,058	17,348	23,758	17,948
2026	24,823	18,019	25,568	18,657
2027	26,375	18,341	27,157	19,012
2028	27,906	18,715	28,705	19,400
2029	29,414	19,133	30,216	19,821
2030	30,794	19,622	31,633	20,341
2031	32,276	20,129	33,055	20,796
2032	33,641	20,752	34,465	21,459
2033	34,957	21,415	35,789	22,128
2034	36,221	22,235	36,980	22,886
2035	37,367	23,104	38,115	23,745
2036	38,517	24,059	39,255	24,692
2037	39,690	25,050	40,443	25,695
2038	40,998	26,193	41,741	26,830

Appendix 2B (iv-v) cont.: Capacity Information Directed by the SCC

Unit Name	Nameplate MW
Altavista	71.1
Bath County 1	477.0
Bath County 2	477.0
Bath County 3	477.0
Bath County 4	477.0
Bath County 5	477.0
Bath County 6	477.0
Bear Garden	559.0
Brunswick County	1,472.2
Chesapeake CT 1, 4, 6	51.1
Chesterfield 5	359.0
Chesterfield 6	693.9
Chesterfield 7	219.4
Chesterfield 8	227.2
Clover 1	424.0
Clover 2	424.0
Colonial Trail West	142.4
CVOW	12.0
Darbytown 1	92.1
Darbytown 2	92.1
Darbytown 3	92.1
Darbytown 4	92.1
Elizabeth River 1	129.6
Elizabeth River 2	129.6
Elizabeth River 3	129.6
Gaston 1-4	177.6
Grassfield	20.0
Gordonsville 1	150.2
Gordonsville 2	150.2
Gravel Neck 3	91.9
Gravel Neck 4	91.9
Gravel Neck 5	91.9
Gravel Neck 6	91.9
Gravel Neck GT 1, 2	40.1
Greensville	1,773.3
Hopewell	71.1
Ladysmith 1	178.5
Ladysmith 2	178.5
Ladysmith 3	178.5
Ladysmith 4	178.5
Ladysmith 5	178.5
Lowmoor 1	20.7
Lowmoor 2	20.7
Lowmoor 3	20.7
Lowmoor 4	20.7

Appendix 2B (iv-v) cont.: Capacity Information Directed by the SCC

Unit Name	Nameplate MW
Mt. Storm 1	570.2
Mt. Storm 2	570.2
Mt. Storm 3	522.0
Mt. Storm GT1	18.5
North Anna 1	979.7
North Anna 2	979.7
Northern Neck 1	20.7
Northern Neck 2	20.7
Northern Neck 3	20.7
Northern Neck 4	20.7
Piney Creek	80.0
Possum Point 6	613.0
Possum Point CT 1-6	96.0
Remington 1	178.5
Remington 2	170.0
Remington 3	178.5
Remington 4	178.5
Roanoke Rapids 1-4	100.0
Rosemary	180.0
Sadler Solar	100.0
Scott Solar	17.3
Southampton 1	71.1
Spring Grove	97.9
Stage Coach/Water Strider	80.0
Stratford/Suffolk/White Marsh	15.0
Surry 1	847.5
Surry 2	847.5
Sycamore	42.0
VCHEC	668.0
Warren	1,472.2
Watlington	20.0
Yorktown 3	882.0
Woodland Solar	19.0
Whitehouse Solar	20.0

Appendix 2B (vi): Capacity Information Directed by the SCC

Dominion Energy Virginia
[illegible] East Canal Street
Richmond VA 232[illegible]
www.DominionEnergy.com

Dominion Energy

February 20, 2020

Mr. David Schweizer, P.E.
Manager, Generation
PJM Interconnection
2750 Monroe Boulevard
Audubon, PA 19403

Dear Mr. Schweizer,

Dominion Energy Virginia is requesting deactivation (retirement) of its Chesterfield 5 & 6 generating units located in Chester, Virginia. Chesterfield units 5 & 6 will be deactivated no later than May 31, 2023. Chesterfield units 5 & 6 have been committed into the RPM capacity market through May 31, 2022.

Dominion is requesting that the existing Capacity Injection Rights (CIR's) be transferred to PJM queue requests AF1-128 and AF1-129. Additionally, it is Dominion's understanding that the CIR's for previously deactivated Chesterfield units 3 & 4 have (or will) be applied to PJM queue request AF1-128. The total quantity of CIR's from deactivation will exceed those of the new requested units.

Dominion has performed financial analyses that show that current and forecasted market revenues do not support the continued operation of these units. Over the course of time the expected requirements or implementation dates for environmental or regulatory regulations may change, as well as significant changes in the energy, ancillary, and capacity markets.

Please call Jeff Currier at 804-273-4269 or Scott Gaskill at 804-273-4438 if you require any additional information.

Sincerely,

Joshua J. Bennett
Vice President Technical Services
Power Generation
Dominion Energy Virginia

December 21, 2022

Generator Deactivations
PJM Interconnection
2750 Monroe Boulevard
Audubon, PA 19403

PJM,

Dominion Energy Virginia is notifying PJM of deactivation (retirement) of its Yorktown 3 generating unit located in Yorktown, Virginia, per the PJM Open Access Transmission Tariff OATT). Yorktown 3 will be deactivated after April 1, 2023, and on or before May 31, 2023. Yorktown 3 has been included in Dominion's FRR capacity plan through May 31, 2025 and will be removed upon deactivation.

Please call Jeff Currier at 804-273-4269 or Jacki Vitiello at 804-317-2971 if you require any additional information.

Sincerely,

Jacqueline Vitiello

Jacqueline R Vitiello
Director, Energy Supply
Dominion Energy Virginia

23084-0067

March 1, 2023

Jacqueline R Vitiello
Director, Energy Supply
Dominion Energy Virginia
600 Canal Place
Richmond, VA 23219

Re. Deactivation Notice for Yorktown 3 Generating Unit

Dear Ms. Vitiello,

This letter is submitted by PJM Interconnection, L.L.C. ("PJM"), in response to the notice submitted by Dominion Energy Virginia dated December 20, 2022 notifying PJM of the intent to deactivate the following generating unit located in the PJM region effective on May 31, 2023.

- Yorktown 3 Generating Unit

PJM's System Planning Modeling Department and the affected Transmission Owner performed a study of the Transmission System and found reliability concerns associated with generation deliverability resulting from the deactivation of the above listed generating units. However, there are operational measures in place to keep the transmission system reliable.

Therefore, in accordance with Section 113.2 of the PJM Open Access Transmission Tariff (PJM Tariff), this letter serves to notify you that the deactivation of the above listed unit can occur on the requested deactivation date, and should not adversely affect the reliability of the PJM Transmission System. Any revisions to the requested deactivation date shall require the Generator Owner to provide PJM with a revised notice in accordance with section 113.2 of the PJM Tariff.

Please be advised that PJM's deactivation analysis does not supersede any outstanding contractual obligations between the above listed generating unit and any other parties that must be resolved before deactivating these generators.

Also please note that in accordance with the PJM Tariff Part VI, Subpart C, a Generation Owner will lose the Capacity Interconnection Rights associated with a deactivated generating unit one year from the actual Deactivation Date unless the holder of such rights submits a new Generation Interconnection Request within one year after the Deactivation Date.

In addition, if a generating unit is receiving Schedule 2 payments for Reactive Supply and Voltage Control, the generating unit owner must notify PJM in writing when the unit is deactivated. Moreover, in accordance with the requirements of Schedule 2 of the PJM Tariff, the generation unit owner must: (1) submit a filing to the Federal Energy Regulatory Commission ("FERC") to terminate or adjust its cost-based rate schedule to account for the deactivated or transferred unit; or (2) submit an informational filing to the FERC explaining the basis for the decision not to terminate or revise its cost-based rate schedule.

Please contact Augustine Caven (610-666-8200) (Augustine.Caven@pjm.com) in PJM's Infrastructure Coordination Department if you have any questions about the PJM analysis.

Very truly yours,

David W. Souder

David W. Souder,
Executive Director, System Planning

cc:
Joseph Bowring, MMU <Joseph.Bowring@monitoringanalytics.com>
Paul E. Pfeffer <paul.e.pfeffer@dominionenergy.com>
Lisa R. Crabtree <lisa.r.crabtree@dominionenergy.com>
Jeffery E. Currier <jeffrey.currier@dominionenergy.com>
Wesley Walker <wesley.walker@dominionenergy.com>

Appendix 3A – Generation Under Construction

Company Name: Virginia Electric and Power Company **Schedule 15a**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.(1)	MW Annual Firm(2)	MW Nameplate
Dulles Tied Solar	VA	Intermittent	Solar	2026	27	100
Sweet Sue Solar	VA	Intermittent	Solar	2026	20	74.76
Bridleton Solar	VA	Intermittent	Solar	2026	5	20
Cerulean Solar	VA	Intermittent	Solar	2026	16	62
Courthouse Solar	VA	Intermittent	Solar	2026	44	167
Ivy Landfill Distributed	VA	Intermittent	Solar	2025	1	3
Racefield Distributed	VA	Intermittent	Solar	2025	1	3
Kings Creek Solar	VA	Intermittent	Solar	2026	5	20
Southern VA Solar	VA	Intermittent	Solar	2025	33	125
Moon Corner Solar	VA	Intermittent	Solar	2026	16	60
North Ridge Solar	VA	Intermittent	Solar	2026	5	20
CVOW - Phase 1 (2587MW)	VA	Intermittent	Wind	2027	793	2587
Dulles Tied Storage	VA	Peak	Grid	2026	44	50
Shands Storage	VA	Peak	Grid	2026	14	15.7

(1) Commercial operation date

(2) Solar firm based on average ELCC value

Appendix 3B – Planned Generation Under Development

Company Name: Virginia Electric and Power Company **Schedule 15c**

UNIT PERFORMANCE DATA

Planned Supply-Side Resources (MW)

Unit Name	Location	Unit Type	Primary Fuel Type	C.O.D.[1]	MW Summer	MW Nameplate
Under Development						
CE-4 Solar	VA	Intermittent	Solar			
CE-4 Distributed Solar	VA	Intermittent	Solar			
Storage	VA	Peak	Grid			
Combustion Turbines	VA	Peak	Gas	2027		

(1) Estimated commercial operation date.

Appendix 3C - List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Cemetery Road Sub - 115kV Delivery - DEV	115	Jan-24	VA	5.0
Lockridge - Add Three TX - DEV	230	Jan-24	VA	1.5
Sinai - 115kV Delivery - Add 2nd TX - DEV	115	Feb-24	VA	0.5
Winters Branch 230kV Delivery - Add 4th TX - DEV	230	Mar-24	VA	0.3
Opal 230 kV Delivery - DEV (New)	230	Apr-24	VA	0.8
Techpark Place SUB - New 230kV Delivery - DEV - Engineering Assessment	230	Apr-24	VA	25.0
Quantico Tx 1 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Quantico Tx 2 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Deep Creek Tx 1 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Alexanders Corner Tx 1 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Tunis Tx 2 Replace Ground Switch With Circuit Switcher	115	Apr-24	NC	0.3
Brown Boveri Tx 1 Replace Ground Switch With Circuit Switcher	115	Apr-24	VA	0.3
Brickyard 230kV Delivery - Dominion	230	May-24	VA	6.6
Lincoln Park 230kV Delivery - DEV	230	Jun-24	VA	19.3
230 kV Line Extension Cannon Branch to Winters Branch	230	Jun-24	VA	38.5
Mt Storm Substation GIS	500	Jun-24	VA	69.0
Cloud Sub - 230 kV Delivery (MEC) -Coleman Creek DP - Extend Line #235 Double Circuit Chase City	230	Jun-24	VA	81.0
Easters Sub - 230 kV Delivery (MEC) - Timber DP	230	Jun-24	VA	20.0
EPG - Add 2nd and 3rd TX - DEV	230	Jun-24	VA	1.5
Line #224 Lanexa to Northern Neck Rebuild and second circuit	230	Jun-24	VA	112.2
DTC 230kV Delivery - DEV	230	Jun-24	VA	60.3
City of Franklin P&L DP#4 (Pretlow) - New 115kV Delivery Point	115	Jun-24	VA	1.3
Line #141 Balcony Falls to Skimmer and Line #28 Balcony Falls to Cushaw Rebuild	115	Jun-24	VA	30.9
Line 100 Harrowgate to Locks EOL Partial Rebuild	115	Jun-24	VA	9.3
Line 2008 Uprate - Loudoun to Cub Run	230	Jun-24	VA	3.0
Line 2008 Uprate - Cub Run to Walney	230	Jun-24	VA	2.5
Line #2242 Uprate - Dulles to Lincoln Park	230	Jun-24	VA	5.0
Nimbus 230kV Delivery - DEV	230	Jul-24	VA	12.0
Lucky Hill Substation	115/230	Jul-24	VA	7.5
Aviator 230kV Delivery - DEV	230	Sep-24	VA	42.0
Altair 230kV Delivery - NOVEC	230	Sep-24	VA	15.0
Trappe Rock 230kV Delivery - NOVEC	230	Sep-24	VA	8.0
Northstar 230 kV Delivery - NOVEC	230	Nov-24	VA	8.0
Thunderball (Wildwood) 230kV Delivery - NOVEC	230	Nov-24	VA	8.0
Line #53 (Chesterfield - Kevlar) Install Reymet Tap	115	Nov-24	VA	3.0
Line 53 and Line 72 EOL Partial Rebuild - Chesterfield to Brown Boveri Tap	115	Dec-24	VA	9.8
Line #1001 Battleboro to Chestnut EOL Rebuild	115	Dec-24	NC	14.0
Interconnection 230 kV Delivery - DEV	230	Dec-24	VA	16.0
Idylwood to Tyson's - New 230kV Line	230	Dec-24	VA	210.0
Lines #2063 and Partial #2164 Rebuild (Loudoun-OX CPCN)	230	Dec-24	VA	19.0
Lines #2181 and #2058 Hathaway - Rocky Mount (DEP) EOL Rebuild	230	Dec-24	VA	13.0
Line #254 Clubhouse-Lakeview EOL Rebuild	230	Dec-24	VA/NC	27.0
Line #1024 Chestnut - S Justice Branch EOL Rebuild	115	Dec-24	NC	5.1
Line #14 (Fudge Hollow to the demarcation point of AEP) EOL	138	Dec-24	VA	30.0
Stratus 230kV Delivery - DEV_Engineering	230	Dec-24	VA	24.0
Rixlew 230 kV Delivery - NOVEC	230	Dec-24	VA	10.0
Garysville 230kV Delivery - ODEC(PGEC)	230	Dec-24	VA	3.0
Convert 115kV Line #172 Liberty-Lomar and Line#197 Cannon Branch-Lomar to 230kV	230	Dec-24	VA	28.0

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Appendix 3C - List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Partial Line#5 Fork Union to Cunningham DP Retirement	115	Mar-25	VA	3.0
115kV Partial Line #83 Rebuild	115	Mar-25	VA	25.3
Park Center 230kV Delivery - DEV	230	May-25	VA	10.0
Relieve Line #219/#2066 Load Drop - Loop Trabue back to Midlothian Sub (Open Window Project)	230	May-25	VA	6.2
Charlottesville to Gordonsville 230kV Series Reactor	230	Jun-25	VA	11.4
Line #2210 Reconductor - Brambleton to Evergreen	230	Jun-25	VA	2.3
Line #2172 Reconductor - Brambleton to Evergreen	230	Jun-25	VA	2.3
Line #2213 Reconductor - Yardley to Cabin Run	230	Jun-25	VA	1.7
Line #514 (Goose Creek - Doubs(FE)) EOL	500	Jun-25	VA	7.6
Replace Overdutied 230kV Breaker L282 at Clifton Substation	230	Jun-25	VA	0.5
Line #2214 Uprate - Buttermilk to Roundtable	230	Jun-25	VA	4.8
Line #2186 Uprate-Shellhorn to Enterprise	230	Jun-25	VA	4.0
Line #2031 Uprate- Enterprise to Greenway to Roundtable	230	Jun-25	VA	5.9
Line #2223 Uprate- Roundtable to Lockridge	230	Jun-25	VA	2.6
Line #2188 Uprate-Shellhorn to Greenway to Lockridge	230	Jun-25	VA	3.8
Line #2218 Uprate - Sojourner to Runway DP to Shellhorn	230	Jun-25	VA	6.5
Line #2137 Uprate- Sojourner to Mars	230	Jun-25	VA	1.4
Line #502 Terminal Upgrade-Loudoun to Mosby	230	Jun-25	VA	6.3
Line #584 Terminal Upgrade-Loudoun to Mosby	230	Jun-25	VA	6.4
230kV Line Extension to Relieve Cloverhill Loop (Winters Branch -	230	Jun-25	VA	6.0
Line #2151 Uprate - Railroad DP to Gainesville	230	Jun-25	VA	6.1
Uprate Line 249 from Carson to Locks to Resolve Gen Deliv Violation	230	Jun-25	VA	22.0
Line #105 Tarboro-Parmele EOL Rebuild	115	Jul-25	NC	24.5
Butler Farm Sub - 230kV Delivery-DEV- Bailey DP-New Finneywood 500/230kV Sub	230/500	Jul-25	VA	220.0
Evans Creek Sub - Roanoke DP - 230kV Delivery - DEV	230	Aug-25	VA	30.0
Tunstall Sub - Hillcrest DP - 230kV Delivery - DEV -New Unity 500/230kV Sub	230	Aug-25	VA	140.0
Raines Sub - Interstate DP - 230kV Delivery - DEV	230	Aug-25	VA	20.0
Line #108 Boykins to Tunis EOL Rebuild	115	Dec-25	NC	46.0
Peninsula - TX 4 Replacement and 230kV Ring Bus	230	Dec-25	VA	27.2
Dawkins Branch 230kV Delivery - NOVEC (Iron Mountain)	230	Dec-25	VA	16.0
Takeoff 230kV Delivery Add Transformers - DEV	230	Dec-25	VA	20.0
Install 2nd 115kV 33.67 MVAR Cap bank at Harrisonburg	115	Dec-25	VA	1.3
Build new Walnut Creek 115 kV switching station	115/230	Dec-25	VA	24.3
Takeoff Substation 230kV interconnection for Poland Loop	230	Dec-25	VA	28.0
230kV Line #293 (Staunton-Valley) and 115kV Partial Line #83 Rebuild	115/230	Dec-25	VA	44.8
Hornbaker Sub-Avanti DP-NOVEC	230	Dec-25	VA	45.0
Line #81 and Partial Line #2056 Rebuild	115/230	Dec-25	NC	27.1
230kV to Relieve Waxpool Loop	230	Dec-25	VA	5.7
Line #2010 Underground Relocation	230	Dec-25	VA	40.0
230kV Line Extension to Relieve Poland Loop	230	Dec-25	VA	36.0
Line #569 (Loudoun to Morrisville) Partial Rebuild 1.3 miles	500	Dec-25	VA	4.2
Line #2209 Uprate Evergreen Mills to Yardley	230	Dec-25	VA	5.0
Line #2095 Uprate - Cabin Run to Shellhorn	230	Dec-25	VA	8.0
Line #2007 Lynnhaven to Thalia EOL Rebuild	230	Dec-25	VA	28.7
Line #2019 Greenwich to Thalia EOL Partial Rebuild	230	Dec-25	VA	14.3
Replace Brambleton Overdutied 230kV Breakers	230	Dec-25	VA	28.0
Line 265 Uprate - Sully to Takeoff	230	Dec-25	VA	2.0
Build New Duncan Store 115kV Switching Station	115	Dec-25	VA	11.0

Appendix 3C - List of Planned Transmission Projects during the Planning Period

Project Description	Line Voltage (kV)	Target Date	Location	PJM RTEP Cost Estimates ($M)
Line 2011 Uprate - Cannon Branch to Clifton	230	Dec-25	VA	31.7
Line #183 EOL	115/230	Dec-25	VA	30.0
Line #2114 Reconductor - Remington CT to Rollins Ford	230	Dec-25	VA	28.9
Partial Line #81 Carolina - S Justice Branch EOL Rebuild - Double Circuit Sections with Line #2056	115	Dec-25	NC	3.4
Line #77 Carolina-Roanoke Rapids Hydro EOL Rebuild	115	Dec-25	VA	7.4
Harrisonburg TX#6 EOL	69/230	Jan-26	VA	3.2
Mint Springs 230 kV Delivery - NOVEC	230	Jan-26	VA	16.0
Germanna 230kV Delivery - DEV	230	Apr-26	VA	55.0
Bring 2-230 kV Sources into White Oak SUB and Resolve 300 MW Load Loss Violation - Engineering Assessment	230	Apr-26	VA	28.0
Line 2104 Partial Uprate to Resolve Gen Deliv Violation	230	Jun-26	VA	20.2
Line 29 and 252 Possum Point to Aquia Harbor Rebuild	115/230	Jun-26	VA	38.0
Possum Point 2nd 500-230 kV TX (Ox Overloads) (PP 500kV - PP 230kV)	230/500	Jun-26	VA	23.1
Line 202 Uprate - Clark to Idylwood	230	Jun-26	VA	8.0
Line #29 Fredericksburg to Possum Pt Partial Rebuild	115	Jun-26	VA	19.2
Line #126 Partial Rebuild to Resolve Gen Deliverability Violation	115	Jun-26	NC	18.8
Convert Line 29 to 230 kV and Resolve 300 MW Load Loss Violation	115/230	Jun-26	VA	9.4
Line 211 228 Chesterfield to Hopewell Partial Rebuild	230	Jun-26	VA	7.4
Line #2226 Partial Rebuild - Clover to Easters (DNH)	230	Jun-26	VA	34.0
Install Cap Bank at Cloud 115kV Bus	115	Jun-26	VA	1.5
Line #574 Elmont-Ladysmith Rebuild	500	Jun-26	VA	93.0
Install Cap Bank at Lexington substation	500	Nov-26	VA	6.3
Bristers 500-230 kV TX Expansion	230/500	Dec-26	VA	65.0
Line #205 Locks to Tyler Rebuild (DNH)	230	Dec-26	VA	27.0
Line #9290 (Ox to Braddock) and Partial Line#2097 Uprate	230	Dec-26	VA	44.0
Line #2080 Uprate - Liberty to Railroad DP	230	Dec-26	VA	1.5
Line #2163 Uprate - Vint Hill to Liberty	230	Dec-26	VA	13.0
Line #2187 and #2228 Uprate - Pioneer DP to Liberty	230	Dec-26	VA	11.4
Line #272 (Dooms to Grottoes) EOL Rebuild	230	Dec-26	VA	30.8
Line #2056 Hornertown to Hathaway EOL Rebuild	230	Dec-26	NC	49.1
Occoquan 500-230 kV TX Expansion	230/500	Dec-26	VA	84.0
Remington CT 230 kV Terminal Upgrades (Line #2114)	230	Dec-26	VA	1.5
Idylwood - Convert Straight Bus to Breaker-and-a-Half	230	Dec-26	VA	159.0
Davis Drive - 230kV Ring Bus Expansion - Line Extension	230	Jun-27	VA	20.0
Ocean Court 230kV Delivery - DEV	230	Jun-27	VA	8.0
Spring Hill 230 kV Delivery - Dominion	230	Aug-27	VA	35.0
Potomac Yards Undergrounding & Glebe GIS Conversion	230	Sep-27	VA	202.0
Line #209 and Line #58 Skiffes to Yorktown EOL Partial Rebuild	230	Sep-27	VA	13.5
Partial Line #10 (Goshen to Craigsville) EOL Rebuild	115	Dec-27	VA	22.5
Nokesville to Hornbaker 230 kV Line	230	Dec-27	VA	139.0
Vint Hill 500-230 kV Expansion	230/500	Dec-27	VA	110.0
Line #557 (Chickahominy to Elmont) EOL Rebuild	500	Jun-28	VA	58.2
500-230kV Line Extension - Southern Option	230/500	Dec-28	VA	693.8
Barrister 230kV Delivery - DEV	230	Dec-28	VA	24.0